THE COSTS OF TRANSPORTATION FUEL FROM METHANOL VERSUS OIL SANDS

Brian D. Sumner
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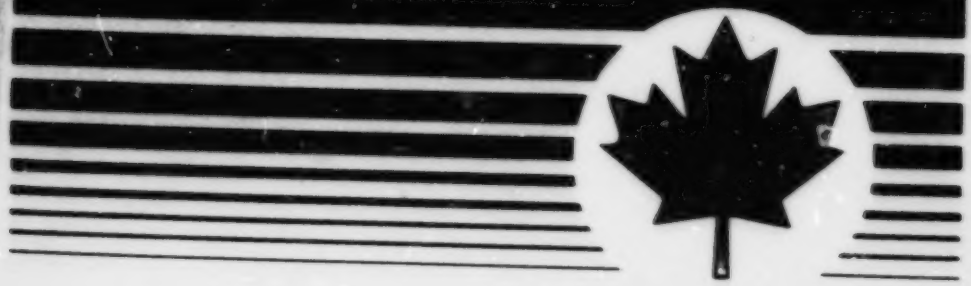

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KEY WORDS

cost estimates

cost overruns

gasoline from oil sands

learning curve effects

methanol from natural gas

Ocelot

supply prices

Syncrude

PREFACE

This report was prepared for the National Research Council of Canada on a contract basis by the Canadian Energy Research Institute. The research was undertaken during the period from November 1983 to May 1984.

The authors would like to thank Dr. Ralph Overend and Mr. Rene Pigeon of the National Research Council for many stimulating ideas which resulted in a challenging project. We would also like to thank the various industry representatives who provided Institute research staff with information. Special thanks are due to Jeannette Stinn for her tireless typing efforts.

EXECUTIVE SUMMARY

This report examines the relative economic attractiveness of two alternative ways of supplying motor fuel in Canada in place of imported or conventional crude oil. The two options are:

- to build and operate a series of medium-size methanol plants using domestic natural gas as a feedstock and to blend the methanol with gasoline; or
- to build and operate a synthetic oil sands plant similar to the existing Syncrude Canada Ltd. plant, to refine the output into motor gasoline and deliver it to the same set of blending locations as in the first option.

The five primary objectives of this report are:

- to estimate a unit supply price of automotive energy for both fuel options;
- to review the technological and economic risks associated with the two fuel options;
- to investigate the potential cost-reducing effect on the supply prices obtained through the learning phenomenon of repeated construction of identical methanol plants;
- to investigate the effects of a set of varied construction time schedules for the several methanol plants on total cost of that fuel option; and
- to assess the regional income and employment impacts of the construction phase of the oil sands and the methanol plants with the aid of the Statistics Canada Input-Output Model.

This is a "social cost" evaluation in the sense that it excludes all taxes and royalties. Two criteria for economic attractiveness have been employed to determine relative advantages of providing automotive fuel. The results obtained tend to reinforce each other in suggesting that while at lower discount rates synthetic gasoline is less expensive, at higher discount rates, the two fuel options are quite comparable with methanol blends being more attractive on the basis of supply cost, as the real rate of discount rises beyond about 8.5 percent. The other main findings are summarized as follows.

There are many uncertainties facing both the oil sands and methanol fuel options which can result in significant impacts on either project. An oil sands development can be expected to experience difficulties related to its size, large front-end loaded investment, technology which needs improvement and complicated logistics. On the other hand, methanol blends may experience driveability and driver acceptance problems. Both fuel options will be affected by developments in the world oil market, where a weakening world price of oil will lessen the economic attractiveness of both.

The effects on capital expenditures of sequentially constructing identical methanol plants have been investigated. The results indicate that although some cost savings are attainable, these translate into relatively small reductions in transportation fuel supply prices.

Four cases were specified to investigate the effects of different construction period scheduling for both the synthetic crude oil and methanol plants. The results show that the discount rate used to obtain the present value of total costs in each case is a critical variable. At low rates of discount (5 to 8 percent) the synthetic crude oil option is less expensive, while at higher rates (8 to 15 percent) methanol is the cheaper option.

The analysis indicates that significantly greater regional effects on both income and employment would result from the construction of an oil sands plant compared with three methanol plants. This result is not surprising given large differences in respective capital expenditures, technological complexities and the lengths of construction periods for the two options.

Chapter 1
BACKGROUND

A major objective of Canada's National Energy Program is the achievement of self-sufficiency in crude oil production. At one time, Alsands and fifteen other similar oil sands projects were planned for completion by the end of this century. In retrospect, the focus of national energy policy on these very large (giga) projects may be questioned, particularly in the light of experiences of the Syncrude and Alsands plants. The Syncrude project has only recently achieved its target production of 20 x $10^3 m^3$/stream day (125,000 bbls/stream day) since beginning in the fall of 1978. The Alsands consortium shelved their project following steep escalation of costs and the inability to reach an agreement with the two levels of governments on a suitable fiscal regime for the plant.

These developments have given rise to consideration of an alternative strategy to attain the same objective. Small-scale methanol production from relatively abundant natural gas oriented toward local transportation fuel markets along Canada's gas pipelines could have technological and economic advantages. One important feature of the methanol alternative is the focus on smaller-scale (mega) projects rather than the giga projects of a much larger dimension.

1.1 Objectives and Assumptions

There are five basic objectives for this study. The first is to estimate and compare the overall cost of transportation fuel energy generated by a Syncrude-type oil sands plant and several small-scale (480,000 cubic metres/year) methanol plants producing an equal amount of total transportation fuel energy. The methanol plants will be assumed to use natural gas as feedstock.

The second objective is to review the technological and financial risks associated with the two fuel options, as well as the likelihood and reasons for cost overruns and performance shortfalls associated with a large scale oil sands project. Since the two options imply fundamentally different technologies, construction and operation

time profiles and costs, their respective technological and financial risks will also vary.

The third objective is to assess the effects of repeatedly constructing several identical methanol plants on the cost of construction.

The fourth objective is to investigate the effects of a set of varied construction time schedules for the several methanol plants on total cost of that fuel option. And the fifth and final objective for this study is to assess the relative impacts on regional income and employment of the construction phase of the two ways of obtaining transportation fuel.

The oil sands plant is assumed to be located in northern Alberta, while the methanol plants are located along the existing Canadian natural gas transportation network. Costs of building the refineries and the gasoline transportation infrastructure are implicitly included by means of the refining and gasoline transportation charges (see Figure 2.1 in Chapter 2).

Construction is assumed to start in 1975 with some production commencing after 4 years in the case of the oil sands plant and full production after 2 years for methanol plants. The analysis is completed in 1982 Canadian dollars. Costs for the methanol and the tar sands plants were escalated with the same price index, namely the Gross National Expenditure Deflator, assuming that if plants for the two options were to be rebuilt, their construction costs would inflate at the same real rates. Methanol, cosolvent and regular gasoline are assumed to be blended at refineries with 90 percent of gasoline blended with 10 percent of methanol and cosolvent. Refinery gate pricing is used to compare gasoline costs from the synthetic crude oil, including the cost of pipelining to the refinery and of transporting to the same set of blending refineries for the methanol option. The methanol-cosolvent blend is presumed to provide the same transportation energy in kilometres per cubic metre that gasoline does.

With respect to the objective of oil self-sufficiency, methanol blends can displace the need for crude oil-derived gasoline. In the present analysis the amount of methanol needed, and thus the number of new methanol plants required, is basically determined by the amount of gasoline energy which can be obtained from one synthetic oil sands plant similar to Syncrude. The maximum amount of methanol which can be

absorbed by the transportation fuel market is determined by the methanol-to-cosolvent ratio in the blended fuel and its penetration of the fuel market in Canada. For instance, if a one-to-one ratio is assumed, then the maximum amount of methanol which can be absorbed by the market will be 5 percent (10 percent with cosolvent) of the entire domestic motor gasoline sales. In other words, a 100 percent penetration of the Canadian fuel market by the blended fuel will set the maximum of methanol which can be used.

1.2 Methodology

The final cost comparison will be made between the overall supply prices of gasoline refined from synthetic crude oil and of methanol-cosolvent blend delivered at the same transportation fuel markets.

A supply price is defined as the minimum price, accounting for both capital and operating costs, at which a producer would proceed with production. The method of developing the supply price concept will be clearly outlined. The entire analysis excludes all taxes and royalties in order to provide a comparison from a social standpoint.

The concept of supply price is also used in the analysis of learning curve effects associated with repeatedly constructing identical methanol plants.

For the purpose of investigating the effects on total costs of different plant scheduling between the two fuel options, the present values of all associated costs are calculated. Four different cases are analyzed and the present values of total costs are shown for each.

Assessment of the regional impacts on income and employment of the two competing ways of obtaining automotive fuel is undertaken using Statistics Canada's Interprovincial Input-Output Model. The model delineates economic activity in terms of income and employment at both the provincial and national levels.

1.3 Study Organization

The remainder of the study is organized as follows. The supply price estimates of the two fuel options are developed in Chapter 2. The various technological and economic uncertainties facing oil sands development are also discussed. Chapter 3 deals with the learning

curve effects of repeatedly constructing identical methanol plants, as well as the effects of varied scheduling of methanol plant construction. Chapter 4 analyses the results of the regional impacts on income and employment of the two fuel options considered. The last chapter presents overall conclusions of this report. Detailed data tables and background information are found in Appendix A and Appendix B, respectively.

Chapter 2

SUPPLY PRICE ESTIMATES OF THE TWO FUEL OPTIONS

2.1 Introduction

This chapter is primarily devoted to estimating supply prices for the oil sands and methanol options. Supply price is defined in the following section while in Section 2.3 the number of production facilities for equivalent amounts of fuel is determined. Based on this calculation, supply prices for three locations are produced. In the final two sections the uncertainties surrounding both oil sands and methanol options are documented.

2.2 The Concept of Supply Prices

In order to compare the relative economic attractiveness of various types of motor fuels, it is useful to estimate a supply price for each type. A method first developed by Bradley is used to determine the real average resource cost per cubic metre of production which must be recouped by the producer over the lifetime of the project. In other words, it is the average price per cubic metre which must be earned to pay back the capital and operating costs of all facilities used, plus the cost of money. A detailed exposition of this methodology is given in Appendix B.

2.3 Methanol Requirements

The following assumptions have been made in order to determine the number of methanol plants which would be required to produce enough methyl alcohol to replace the synthetic gasoline output of an oil sands plant.

Assumptions: - Methanol and the requisite cosolvents which may be used, such as isopropanol or isobutanol have a useful (combustion) energy content equivalent to regular motor gasoline on a volume basis.[1] No credit for butane back out has been provided.

- The Syncrude-sized synthetic crude oil plant modelled in this report has a noted maximum output of 6.5 x $10^6 m^3$/yr (41 x 10^6 bbls/yr). It is further assumed that the gasoline yield from this oil, based on Alberta refinery averages in 1983, is 40 percent.

- The typical methanol plant modelled in this report produces at full capacity of 480,000 m^3/yr. Two cases can be identified with regard to the use of cosolvents.

Case I: Two parts of methanol can be blended with one part of cosolvent. This implies that 3.6 methanol plants will be required to produce an equivalent output. This is determined as follows: (6.5 x $10^6 m^3$) x 0.40 = 2.6 x $10^6 m^3$ of gasoline to be displaced. This is equivalent to 2.6 x $10^6 m^3$ of alcohol blend (invoking the above assumptions). If 2/3 of the blend is to be methanol, then (2.60 x 10^6) x 2/3 = 1.73 x $10^6 m^3$ divided by the output of one plant (480 x $10^3 m^3$) = 3.6 plants required.

Case II: Alternatively, if a one part methanol to one part cosolvent blend is assumed, then 2.6 x $10^6 m^3$ of displaced gasoline demand divided by two parts = 1.3 x $10^6 m^3$ of methanol divided by 480 x $10^3 m^3$/plant = 2.73 methanol plants.

Because of more favourable combustion characteristics, it is assumed that three methanol plants will be built, using the one-to-one ratio between methanol and cosolvent.

A ratio of one part methanol to one part cosolvent will largely eliminate problems which would occur with smaller amounts of cosolvent. In Canada motorists would be sensitive to cold-starting problems which do occur at low temperatures with lower amounts of cosolvent. Road tests with a one-to-one ratio indicate that the driveability characteristics of the alcohol blend could be equivalent to normal gasoline.

Canada's largest reserves of natural gas are in Alberta, while the largest motor gasoline market is in Ontario which represents 37 percent of the Canadian market.[2] Quebec, British Columbia and

Alberta follow with 22 percent, 13 percent and 11 percent, respectively. Natural gas feedstock for methanol production is found quite apart from major motor fuel markets, thus compounding the logistics of methanol plant site selection. The question is whether methanol plants constructed for the purpose of supplying fuel should be located near feedstock supplies or near motor fuel markets. As indicated above, three methanol plants are to be built. While one can be constructed in Alberta to serve the Western market, site selection for the remaining two is less obvious. In order to solve the site-selection problem, transportation costs of both natural gas and methanol must be investigated.

The cost of shipping methanol from Alberta to Ontario and Quebec markets must be compared to the cost of shipping natural gas from Alberta to methanol plants in Ontario and Quebec. Rail cost estimates range from $\$21/m^3$ ($1983) for a unit train system to $\$50/m^3$ ($1983) for a single car train to ship methanol from Alberta to Ontario. Pipelining represents a possible transportation alternative but there is no commercial experience and only limited research has been conducted to determine the technical feasibility. Preliminary cost estimates for shipment through Interprovincial Pipeline or Cochin Pipeline range from $\$11/m^3$ ($1983)[3] to almost $\$50/m^3$ ($1983).[4] Natural gas transport tariffs are a fraction of the cost at $\$0.035/m^3$ ($1983).[5] However, almost eight hundred times as much natural gas needs to be shipped in order to produce the amount of methanol that otherwise would have been shipped.[6] The equivalent cost of transporting natural gas is therefore in the order of $\$28/m^3$ ($1983) of methanol.

The most economic alternative is therefore not clear. Due to the lack of experience in pipelining or using a unit train system for shipping large amounts of methanol, considerable uncertainty is attached to methanol transport cost estimates. On this basis, natural gas shipped from Alberta to methanol plants serving the Southern Ontario and Montreal area markets is the option chosen here.

Figure 2.1 is a schematic diagram displaying the two fuel options.

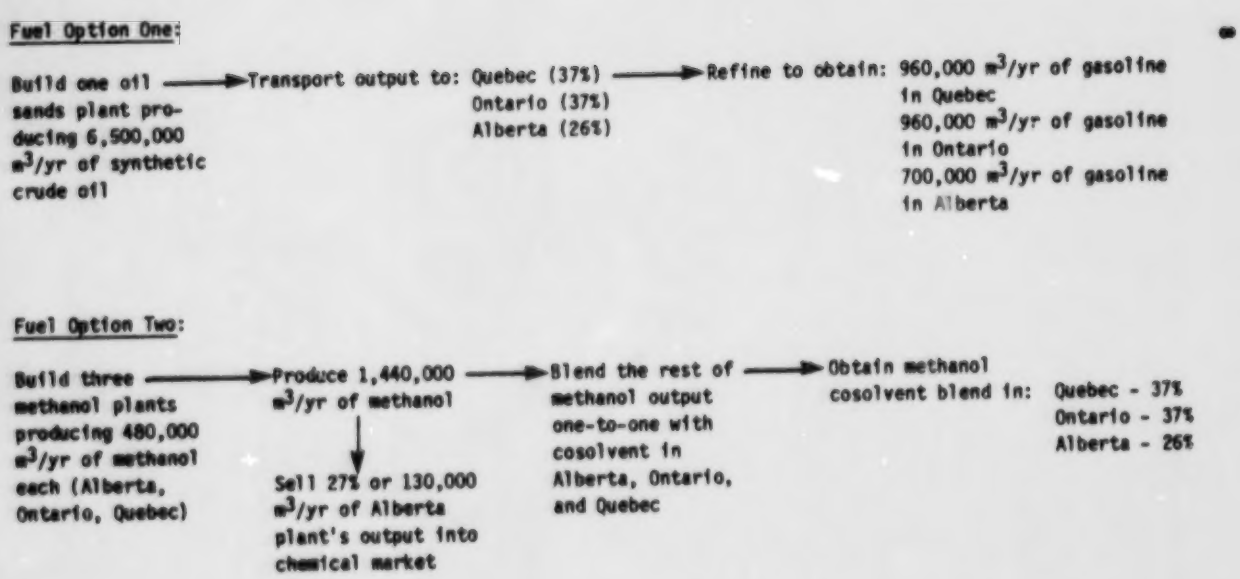

Fuel Option One:
Build one oil sands plant producing 6,500,000 m3/yr of synthetic crude oil
Transport output to: Quebec (37%) Ontario (37%) Alberta (26%)
Refine to obtain: 960,000 m3/yr of gasoline in Quebec 960,000 m3/yr of gasoline in Ontario 700,000 m3/yr of gasoline in Alberta
Fuel Option Two:
Build three methanol plants producing 480,000 m3/yr of methanol each (Alberta, Ontario, Quebec)
Produce 1,440,000 m3/yr of methanol
Sell 27% or 130,000 m3/yr of Alberta plant's output into chemical market
Blend the rest of methanol output one-to-one with cosolvent in Alberta, Ontario, and Quebec
Obtain methanol cosolvent blend in: Quebec - 37% Ontario - 37% Alberta - 26%

FIGURE 2.1: SCHEMATIC DIAGRAM OF TWO FUEL OPTIONS

2.4 Construction and Operating Costs

2.4.1 Oil Sands Plant Costs

The analysis assumes that an oil sands plant would be built in the Fort McMurray area in Alberta with construction beginning in 1975. The plant would utilize the conventional Clark process to extract bitumen from the oil sand and would include facilities to upgrade the bitumen to a naphtha-gasoil blend for pipelining to Edmonton.

Capital costs include construction of the main extraction plant and mining facilities, the utility plant and the pipeline to transport synthetic oil to an Edmonton refinery. Capital costs of refining are implicitly included in the refining charges.

The hypothetical plant would have a design capacity of 20 x $10^3 m^3$/stream day (125,000 bbls/stream day) and a life expectancy of 25 years.[7] The construction period would be 5 years with first plant output appearing in the fourth year at 7 percent of capacity. The expected production profile would be as follows:[8]

Year	Capacity on Stream (percent)
1975	0
1976	0
1977	0
1978	7
1979	24
1980	56
1981	63
1982	73
1983	80
1984-2003	100

The estimates of capital costs for construction of the project were adapted from a study, "The Impact of the Syncrude Project on the Economy of Alberta" produced by Hu Harries and Associates in January 1975.[9] These capital costs were converted to constant 1982 dollars using the Gross National Expenditure (GNE) deflator. The total construction cost is estimated at $4 billion ($1982).

Operating costs were derived from industry estimates. For the Syncrude plant total operating costs are approximately $600 million per year ($1982) at full capacity utilization. This estimate is net of

provincial royalties and taxes and thus represents the real resource cost of operating the plant. The assumption is made that these costs will remain constant in real terms to 2003, the last year of operation of the plant. Capital construction costs, operating costs and output are shown in Appendix A, Table A.1.

2.4.2 Methanol Plant Costs

The model methanol plant used for this analysis is the Ocelot Industries Limited plant built at Kitimat, British Columbia. This plant was designed and built by Partec Lavalin Incorporated and has a design capacity of approximately 480 x $10^3 m^3$ (3 million barrels) of grade AA (chemical grade) methanol per year. It is assumed that identical natural gas-fed methanol plants will be built at the three selected locations. Each plant will employ the well proven Imperial Chemical Industries' low pressure process technology whose patent will expire later this year. The methanol facility consists of one process train with capacity of 1,455 m^3/stream day (330 stream days per annum).

A breakdown of the capital and operating costs for the three operating locations is given in Appendix A, Tables A.2, A.3 and A.4. Total capital investment for a representative full-scale plant is $184 million ($1982).[10] Each plant would take 2 years to complete with 40 percent of the cost borne in the first year and 60 percent in the second year. The project is 100 percent equity financed and the project life is 20 years. If construction starts in 1975 the plant would commence production in 1977 and be retired in 1997.

Operating costs vary between locations due to natural gas feedstock costs. Labour and material costs are assumed to remain constant over the project period. Actual transportation costs to get materials to the Alberta site are negligible as a percentage of the construction costs.

Estimates of non-feedstock operating costs for the methanol plants were obtained from an Ontario Ministry of Energy report.[11] These estimates are net of taxes, profits, return on investment and capital amortization charges.

Feedstock costs are expected to rise in real terms, therefore the feedstock portion of operating costs was escalated according to natural gas price escalation rates forecast to 1996 using the Canadian

Energy Research Institute Oil and Gas Pricing Model. This model provides forecasts of industrial wholesale prices for intra-Alberta sales as well as gas delivered to Ontario and Quebec. These projections were then used to establish the feedstock costs for each plant scenario. Historical series were used for the years 1977 to 1983. These prices are provided in Appendix A, Table A.5.

To put the supply price of methanol on an equal footing with synthetic oil prices, taxes have not been included and the feedstock costs are estimated without federal taxes and provincial royalties to obtain an equivalent real resource cost estimate. Correspondingly, a forecast of industrial wholesale prices for natural gas was established in Alberta net of all taxes. This was then reduced by 35 percent to remove the provincial royalty (35 percent was the average provincial royalty in Alberta in fiscal year 1982).

Feedstock prices in Ontario and Quebec were based upon this Alberta price plus upward adjustments for pipeline tariffs. The tariffs are $\$0.035/m^3$ ($1/Mcf) Edmonton to Toronto and $\$0.009/m^3$ ($0.25/Mcf) Toronto to Montreal. These are assumed to remain constant in 1982 dollars. Feedstock costs are therefore considerably higher in Ontario and Quebec than they are in Alberta.

2.5 Supply Price Estimates

The concept of supply price can be applied to the production of synthetic crude oil or methanol. It can also be applied in a broader sense to determine the relative economic attractiveness associated with generating a level of transportation energy by substituting for conventional oil production or oil imports over a period of time.

The first overall objective of this report is to compare the economic attractiveness of two alternative options which could be chosen to meet the same level of motor fuel demand in Canada determined by the full capacity output of one Syncrude-sized oil sands plant. If the nominal capacity of the plant is 20,000 m^3/day, (125,000 bbls/day) or 6.5 x $10^6 m^3$/yr (41 x 10^6 bbls/yr), then at typical refinery yields (i.e., 40 percent gasoline) 2.6 x $10^6 m^3$/yr (16.4 x 10^6 bbls/yr) of gasoline will be the given level of demand to be met. This demand could then be met by either constructing one oil sands plant or three methanol plants and it will be assumed that this level of demand must also be met (via imports) during the plant construction periods.

In order to compare the two options on the same output footing, that part of the demand level that either option or both cannot meet at the beginning or the end of their production lives is supplied by a make-up gasoline produced from the marginal source, oil imports. In the case of the oil sands plant, the construction time is over 4 years during which full output is not produced. However, the oil sands plant has a longer expected lifetime than the methanol plants. Alternatively, the methanol plants are built more quickly but have a shorter expected life. To allow for these different time schedules it is assumed that conventional oil is refined into gasoline to make up the difference.

2.5.1 Synthetic Gasoline Option

In order to compute a supply price for gasoline via the synthetic oil option, more cost information is required beyond the synthetic gasoline feedstock supply price itself. A major cost component of the option, besides the capital cost of constructing the plant, will be the cost of meeting the given level of gasoline demand while the oil sands plant is being built. Given the historical production profile of Syncrude Canada Ltd., sustained full output cannot be expected until about the tenth year after the start of construction. Table A.6 in Appendix A shows the production profile of gasoline from synthetic oil and the amount of required make-up gasoline which must be supplied from alternative sources (i.e., imports) while the oil sands plant is under construction. This situation is shown graphically in Figure 2.2. Assuming that the oil sands plant has an operating life of 25 years, the time period of this fuel option, including construction, spans the years 1975 to 2003. No make-up gasoline is required after the oil sands plant reaches full output in 1984.

Because crude oil needs to be refined before it can be used as a motor fuel, significant refining charges (capital and operating) are associated with upgrading the oil into gasoline. Available estimates suggest that refining charges in Alberta are approximately $\$47/m^3$ of gasoline yield,[12] while the charges in Eastern Canada are higher; about $\$63/m^3$ of gasoline yield. Every unit of gasoline, whether synthetic or make-up, must then incur a refining charge of at least $\$47/m^3$. Average oil transportation charges to Ontario and Quebec are also included, valued at $\$7.24/m^3$.

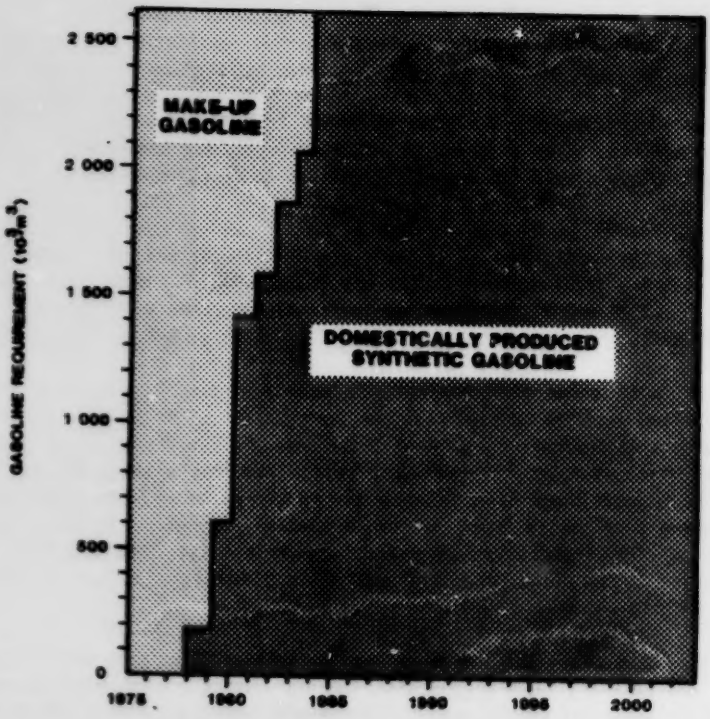


FIGURE 2.2: SYNTHETIC GASOLINE OPTION: SOURCES OF GASOLINE SUPPLY

When oil is refined into gasoline, several other joint products are produced. Most of this associated output is either diesel fuel or fuel oil which is very valuable to the refiner. It is therefore important to provide a credit for these joint products so that the gasoline yield does not bear the entire cost of producing synthetic oil. One way to provide credit for joint products is based upon their shares of the revenue obtained from selling a refined cubic metre. It has been estimated that products refined jointly with gasoline will account for about 55 percent of the revenue cubic metre and, therefore, a 55 percent credit has been applied to the cost of synthetic oil, as well as to the cost of imported oil required as feedstock for make-up gasoline. In other words, refining yields from synthetic oil are here assumed approximately the same as those from imported oil, and oil costs are reduced by a factor of 0.55 to account for the joint product credit. (This credit accounting is outlined in Appendix B.)

The third column in Table A.6, "Make-up Gasoline Costs," reflects the credit applied to the price of international oil landed at Montreal (as forecast by the CERI Oil and Gas Pricing Model and shown in Table A.7) and also the cost of refining each cubic metre of make-up gasoline in the three centres.

With these cost estimates a complete supply price for the synthetic gasoline option can be calculated using the algorithm developed in Appendix B. Table 2.1 presents the results obtained using three discount rates. This supply option provides a per cubic metre price estimate, net of all taxes and royalties, for $2.6 \times 10^6 m^3$ of gasoline supplied in three different centres, Edmonton, Toronto, and Montreal for a period of 29 years. Of that total, $700 \times 10^3 m^3$ is supplied to the Alberta market and $960 \times 10^3 m^3$ is supplied to both the Ontario and Quebec markets.

A supply price has also been calculated from importing crude oil and refining it into gasoline for the Quebec market only (2.606 million cubic metres per year). The supply price is $\$311.87/m^3$ at 5 percent discounting, $\$298.34/m^3$ at 10 percent discounting and $\$287.02/m^3$ at 15 percent discounting. The synthetic oil option compares favourably with these estimates.

TABLE 2.1

SYNTHETIC GASOLINE OPTION SUPPLY PRICES

Discount Rate (%)	Supply Price of Synthetic Gasoline Feedstock ($/m^3)	Supply Price of Make-up Gasoline and Total Refining Charges ($/m^3)	Total Fuel Supply Price ($/m^3)	Total Fuel Supply Price ($/gigajoule)
5	116.61	135.80	252.41	7.28
10	123.84	157.70	281.54	8.12
15	131.33	175.70	307.03	8.85

NOTE: The supply price of make-up gasoline and refining charges were generated by using the same algorithm which calculated synthetic gasoline feedstock supply price estimates. These two estimates are then added together. All supply prices are based on supplying 2.6 million cubic metres of gasoline annually for a period of 29 years. Option supply prices include all refining charges and transportation charges for the three centres.

2.5.2 Methanol Fuel Options

As mentioned in Section 2.1, three methanol plants would be required to equal the gasoline yield from the output of one Syncrude-sized plant. It is assumed that these three plants would be constructed in Alberta, Southern Ontario and the Montreal area to service three identifiable motor fuel markets. The supply prices for these plants will differ due to pipeline and refining charges. The supply prices of the options include imported oil costs during plant construction, as well as refining charges. The final estimates will therefore vary due to regionally differentiated refining costs, as well as differences in natural gas prices.

A major cost involved in the methanol plant options is the cost of the required cosolvent which must be mixed with the methanol to provide suitable combustion characteristics. It must be noted that current domestic supplies of cosolvent are not nearly adequate to meet the incremental demand of methanol blending. Domestic production facilities would have to be expanded considerably to equal the capacity of the three methanol plants or, alternatively, large volumes would have to be imported.[13] Although this question has not been explored in depth in this report, it is assumed that adequate amounts of cosolvent could be obtained from alternative sources (imports) at a constant real price over the life of the project. The cosolvent price used in this report ($\$420/m^3$) is an average price of domestic and imported products.[14] It is assumed throughout that a one-to-one blend of methanol and cosolvent is used, so that equal amounts of methanol and cosolvent are required for the blended fuel.

Each of the three methanol plants can produce about 480×10^3 cubic metres per year for a total of $1,440 \times 10^3$ cubic metres per year, although only 91 percent of this total is actually used for motor fuel. In Section 2.1 it was determined that only 2.73 methanol plants would be required to produce output (when mixed with cosolvents) equivalent to the oil sands refined gasoline output. It is assumed that three full-scale plants will be built to operate at full capacity in Ontario, Quebec and Alberta. However, the Alberta plant situated in a smaller market is assumed to sell a portion of its output into the chemical market; it is assumed that 73 percent of its output is used for motor fuel and 27 percent is sold into the chemical market. Accordingly, only 73 percent of both capital and operating costs of producing methanol in Alberta are allocated to the motor fuel output.

Additional costs are involved in a supply price estimate for the methanol option, but these are relatively minor. Cosolvent storage tanks would be required at each methanol plant (or a refinery where mixing with gasoline would be done). This would be a one-time cost of $4 million ($1982) per plant. This cost is included in the capital cost estimates.

Corrosion inhibitor which must be used with methanol to prevent corrosion of vehicle fuel system components would involve some extra cost. The estimated cost for this chemical is about $300 thousand per year per methanol plant. This cost is imbedded in the non-feedstock operating costs for all locations and is assumed to remain constant in real terms for the duration of the project.

The other costs of the methanol options are the costs of make-up gasoline. These are determined in the same way as in the synthetic gasoline option where a 55 percent credit is given for the production of joint products in refining. Refining costs for the gasoline are also included. Tables A.8, A.9 and A.10 in Appendix A provide time profiles of the component operating costs of the three methanol options. Table A.11 contains values for the project price deflator.

Figure 2.3 shows the production profile of all three methanol plants which reach 100 percent of required output in the first year of production and continue to produce at that level for 20 years.

Figure 2.4 shows an alternative production profile of the methanol plants as they are constructed and brought on stream in sequence.

Individual supply prices for each of the three methanol plants have then been calculated based on the assumptions given above. The parameters used in the three options are identical with the exception of the capital costs, crude oil and natural gas feedstock costs and the refining charges.

Tables 2.2 and 2.3 provide estimates of option supply prices for each of the three methanol plants at three different discount rates. The supply price for the whole methanol option for the three plants and their make-up gasoline is also shown. In the case where the annual outputs are constant until the end of plant life, the option supply price reduces to the volume-weighted average sum of the

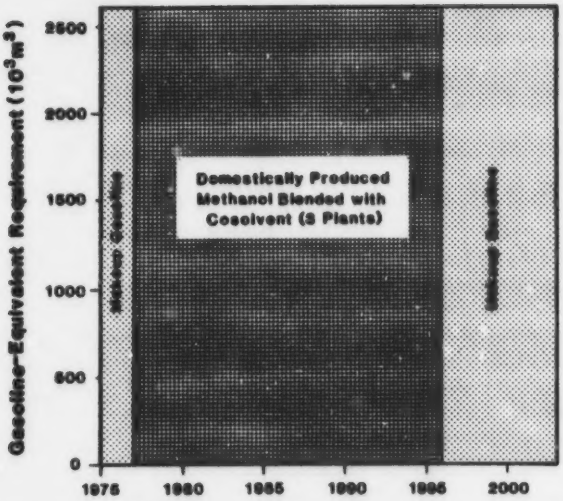


FIGURE 2.3: METHANOL FUEL OPTION 1: SOURCES OF FUEL SUPPLY

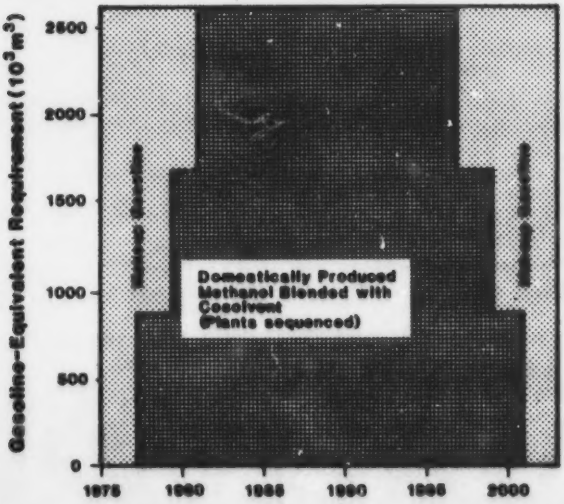


FIGURE 2.4: METHANOL FUEL OPTION 2: SOURCES OF FUEL SUPPLY

TABLE 2.2

METHANOL OPTION SUPPLY PRICES
SEQUENTIAL METHANOL PLANTS[a]
($/m^3 of gasoline equivalent)

Discount Rate (%)	Alberta	Ontario	Quebec	Option Supply Price[b] Without Learning Effects	Option Supply Price[b] With Learning Effects (m=0.2)
5	274.81	291.30	294.06	288.03	279.48
10	269.52	286.01	288.84	282.77	272.36
15	267.64	284.37	287.14	281.05	268.10

[a]Includes all capital costs, cosolvent costs, and make-up gasoline costs including refining charges.

[b]Calculated as the volume-weighted average of the three individual supply prices since these volumes are constant through the lifetimes (see Table 3.3).

TABLE 2.3

METHANOL OPTION SUPPLY PRICES
SEQUENTIAL METHANOL PLANTS[a]
($/gigajoule)[b]

Discount Rate (%)	Alberta	Ontario	Quebec	Option Supply Price[b] Without Learning Effects	Option Supply Price[b] With Learning Effects (m=0.2)
5	7.93	8.40	8.48	8.31	8.06
10	7.78	8.25	8.33	8.16	7.86
15	7.72	8.20	8.28	8.11	7.73

[a]Includes all capital costs, cosolvent costs, and make-up gasoline costs including refining charges.

[b]The conversion factor used is 34.66 gigajoules per cubic metre of conventional leaded gasoline. See Statistics Canada, Quarterly Report on Energy Supply-Demand in Canada, Catalogue 57-003, Quarterly.

individual supply prices of the plants and the gasoline make-up. The supply prices of the synthetic gasoline and methanol options at the various discount rates are then shown graphically in Figure 2.5.

The methanol option supply prices have also been evaluated in dollars per gigajoule based on the assumption that the methanol/cosolvent blend produces equivalent combustion energy on a volume basis to regular motor gasoline. A methanol supply price has also been calculated for an option which includes large learning curve effects. This option is detailed in Chapter 3. The supply price of the option with learning effects provided in Tables 2.2 and 2.3 relates to Case 3 (Sequential Methanol Plants) in Chapter 3.

Tables 2.4 and 2.5 show the methanol and natural gas component supply prices. The methanol supply prices are calculated for each plant and are based on the costs of producing methanol only (no cosolvent or make-up gasoline is included). These prices are given in dollars per cubic metre and dollars per gigajoule.

The natural gas supply price component is then calculated for the option (output of the three plants) based on the cost and quantity of methanol produced exclusive of cosolvent and make-up gasoline for the three plants. Each full scale methanol plant uses about 379,448 x 10^3 m^3 of natural gas per year.

Sensitivity analysis performed on the supply price of methanol from the three plants suggests that reducing the natural gas feedstock price by 50 percent would reduce the supply price significantly. Table 2.6 shows the supply prices of methanol reprinted from Table 2.4 and also supply prices generated by reducing the natural gas feedstock price by 50 percent. The differential is provided as well as the percentage reduction below the "original" methanol supply price.

For the Alberta plant this change reduces the supply price by 11 percent (at 10 percent discounting). For the Ontario and Quebec plants the reductions are even greater at 17 and 19 percent, respectively, due to the greater importance of this feedstock component.

These reductions must be considered in the light of two provisos:

TABLE 2.4

METHANOL AND NATURAL GAS SUPPLY PRICES
($/m^3)

Discount Rate (%)	Methanol			Natural Gas Component
	Alberta	Ontario	Quebec	Three Plants Together
5	126.05	154.74	161.79	$55.25
10	139.76	168.52	175.51	53.43
15	156.31	185.14	192.18	51.92

TABLE 2.5

METHANOL AND NATURAL GAS SUPPLY PRICES
($/gigajoule)

Discount Rate (%)	Methanol			Natural Gas Component
	Alberta	Ontario	Quebec	Three Plants Together
5	3.63	4.46	4.67	$ 1.59
10	4.03	4.86	5.06	1.54
15	4.51	5.34	5.54	1.50

TABLE 2.6

METHANOL SUPPLY PRICES
($/m^3)

	Discount Rate (%)	Original ($/m^3)	With Lower Priced Feedstock ($/m^3)	Differential ($/m^3)	Percentage Reduction (%)
Alberta	5	126.05	110.05	$16.00	13
	10	139.76	124.66	15.10	11
	15	156.31	141.97	14.34	9
Ontario	5	154.74	124.66	30.08	19
	10	168.52	139.26	29.26	17
	15	185.14	156.69	28.45	15
Quebec	5	161.79	128.12	33.67	21
	10	175.51	142.79	32.72	19
	15	192.18	160.22	31.96	17

(1) These are supply prices of methanol only; they do not include cosolvent and make-up gasoline costs or refining and oil transportation charges.

(2) Estimating a pure supply price of natural gas is very difficult--reducing the natural gas price scenario by 50 percent does not pretend to establish such a supply price.

Another sensitivity analysis performed showed that reducing the price of cosolvent for the methanol blending by 30 percent (i.e., from \$420/m^3 to \$294/m^3) will reduce the option supply price by approximately \$63/m^3. Therefore, if a dedicated plant were built in Canada producing cosolvent at a lower price than that of current imports, some cost reduction might be realized.

2.5.3 The Choice of the Rate of Discount

The choice of the rate of discount for any analysis is critical as high discount rates will reduce the present value of a project and hence its likelihood of being financed.

The question of what is the appropriate social rate of discount for Canada has been debated by academics, government officials and other researchers for some time. More recently, this debate resulted in a series of articles producing an estimate of a range between 7 and 10 percent as the median for the rate applicable to social analysis.[15]

To the extent that the present project abstracts from all taxes and royalties, we feel that the above range is appropriate to use.

2.5.4 Conclusions

To the extent that an estimate of the supply price can be taken to indicate relative economic attractiveness between the two fuel options, it can be seen in Figure 2.5 that, for lower real discount rates, synthetic gasoline is cheaper. At discount rates of approximately 8.5 to 15 percent, however, methanol blend becomes the cheaper option, comparing quite favourably with synthetic gasoline as the rate rises. To the extent that the preceding section has suggested a median for the social rate of discount between 7 and 10 percent, it can be seen in Figure 2.5 that gasoline from oil sands is cheaper than methanol at the lower end of this range, but if cost reductions occur due to learning, methanol would become the cheaper option at rates of about 8.5 to 15 percent.

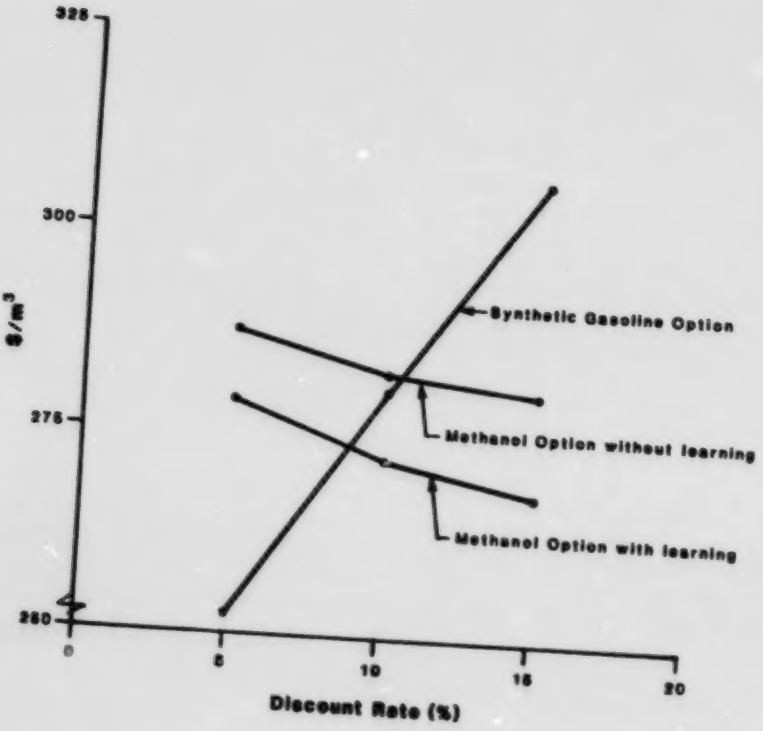


FIGURE 2.5: SUPPLY PRICES FOR THE FUEL OPTIONS

The differences observed in Table 2.2 among the supply prices of methanol for the three selected locations are mainly due to the cost of natural gas feedstock. Thus the supply price for the Alberta location is naturally the lowest, with those of the Ontario and Quebec plants reflecting the added cost of transporting gas from Alberta.

Figure 2.5 also shows that as the discount rate rises the supply price for the methanol option declines slightly, while for the synthetic gasoline option the supply price rises significantly. This reflects the large differences in the operating cost outlays and their timing over the 29-year period for the two options. Sensitivity analysis reveals that reducing the natural gas prices and cosolvent prices would have significant effects on option supply prices.

In a broader energy policy context, before the least expensive fuel option is selected, however, other alternatives such as compressed natural gas or propane should also be compared with the options analyzed here. The fact that the present results show relatively small differences in supply prices at higher rates of discount between synthetic gasoline and methanol blend is a further reason to analyze other alternatives before making a choice.

2.6 Uncertainties Facing Oil Sands Development

There are many uncertainties facing oil sands development which can result in significant impacts on project costs. While the existence of the Athabasca oil sands deposit has generally been known since the 19th century, extraction of synthetic oil from the sands on a commercial scale has only been accomplished in the last 15 years. Suncor Ltd., formerly Great Canadian Oil Sands (GCOS), began mining in 1967 with a rated synthetic crude oil capacity of 7,150 m^3/day (45,000 bbl/day). The Suncor plant was the first to prove the extraction process on such a large scale. As a result of poor economics, by 1976 GCOS had an accumulated deficit of $67 million even with the advantage of a relatively low capital cost per cubic metre due to its construction in the 1960s.[16]

Construction on the Syncrude plant began in 1973 with the first output being produced in 1978. Rated capacity is 20,000 m^3/stream day. This capacity level has been achieved only intermittently in the recent past as bottlenecks have been removed. Figure 2.6 shows Syncrude's production trend since start-up. Syncrude is now in the

midst of a capacity expansion which will allow production of approximately 20,500 m^3/stream day.

The experience gathered to date from these two oil sands plants clearly suggests that there are significant risks involved in this type of investment. Generally, uncertainties can be classified as either economic or technological. They can combine to threaten the viability of each project.

2.6.1 Economic Uncertainties

The most obvious threat to an oil sands venture is the instability of the output price. Although nominal international oil prices had increased rapidly in the 1970s, real prices have seen a dramatic decline in 1983, and further real declines may occur. This has had a negative effect on the forecast revenues of Suncor and Syncrude operations, as well as other oil producers. The Syncrude and Suncor operations have been guaranteed the world oil price for their output. However, current forecasts suggest that there could be no real increase in oil prices until the end of the 1980s or beyond. Thus, the producer accepts the risk that costs may grow in real terms but revenue may decline.

The opportunity cost of money also figures prominently in the evaluation of project risks. Interest rates over the 1977-1982 period, during which the Alsands project was being planned and was eventually cancelled, rose substantially. In 1977 the long-term Canadian rate was about 9-1/2 percent. By the third quarter of 1981 it had reached more than 18 percent. The project would have had to generate a rate of return greater than 18 percent in order to be attractive to the participants.

The oil sands projects are among the largest construction projects ever undertaken in Canada, requiring the expenditure of billions of dollars. The original capital cost estimate for the now defunct Alsands plant in 1978 was approximately $5 billion. This expenditure escalated to around $13 billion by the time the plant was cancelled in 1982, a large amount of which was accounted for by cost inflation and interest expense during the construction. This large amount of capital, combined with high interest rates, resulted in a very large revenue requirement in order to pay back the investment and receive a reasonable rate of return on it.

2.6.2 Technological Uncertainties

Adding to the economic uncertainties are a myriad of technological problems which have plagued both the Suncor and Syncrude operations since their inception. The stream of revenue produced can be reduced by unexpected downtime experienced by the operator (see Figure 2.6). Although a new plant, especially one with new technology, is not expected to produce at full capacity for the first 2 or 3 years, the Syncrude plant has had trouble achieving full capacity utilization within 5 years from start-up. This has further reduced the revenue stream.

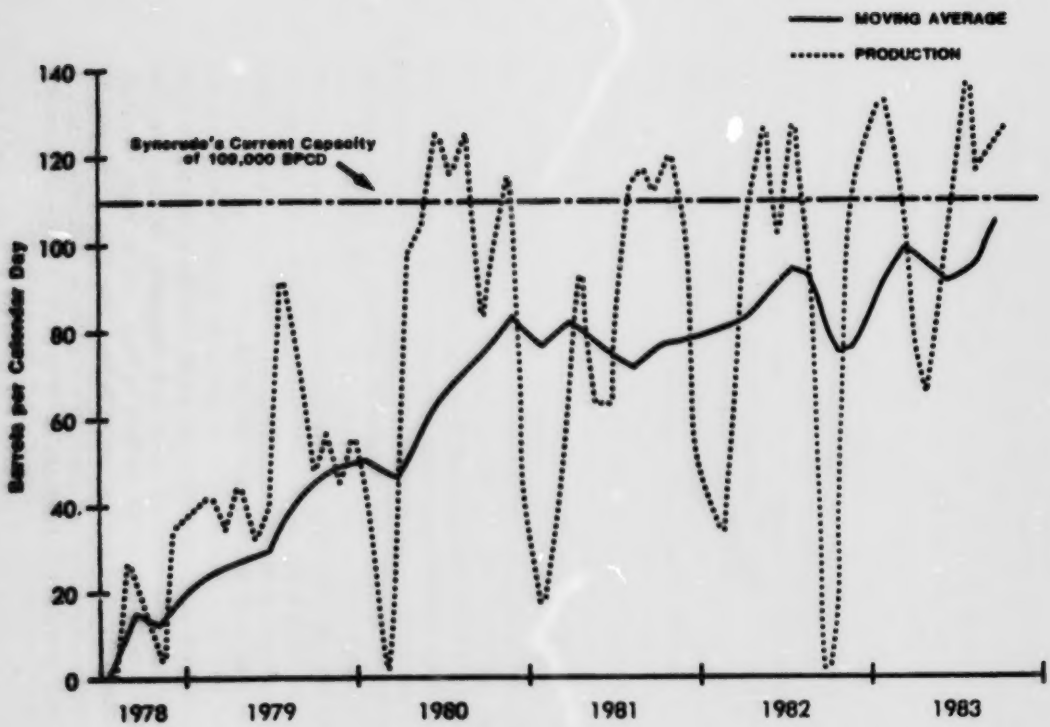
Although problems were expected from the use of a new technology, the extent to which the plants required modifications to deal with them, and the associated costs, were unknown beforehand. Many of the problems simply resulted from the size of the plants: Syncrude is the largest mining operation in the world and the Suncor plant was 100 times the scale of the first major pilot plant built with over 110,000 tonnes of bitumen-laden sand mined every day.

The process currently used to separate the bitumen from sand was first formulated in 1924 and it is still being used in spite of its relatively low energy efficiency.[17]

2.6.3 Other Uncertainties

In addition to the problems caused by scaling up from the pilot plant, the harsh winter climate of northern Alberta has caused many problems. The Suncor and Syncrude plants, designed by Bechtel Corporation, required extensive and costly post-construction modifications to cope with the -50°C winter temperature. This type of winter operation caused much of the equipment to freeze up and malfunction, or not function at all. In order to prevent this, machinery and processes had to be redesigned. Winterization costs alone at Syncrude have been estimated at over $2.5 million during 1982.[18]

There have been other problems with fire and explosions. Some of these problems have resulted in lengthy shutdowns, greatly reducing the output of the plant which in turn reduces the operations annual revenue. Generally speaking, operating below designed capacity greatly increases the average cost per cubic metre produced. Solving some of these problems greatly increased costs.



SOURCE: Syncrude Canada Ltd.

FIGURE 2.6: SYNCRUDE PRODUCTION TREND SINCE STARTUP

Third-generation plants which may be added to oil sands development in the future will benefit from already identified solutions to some of the technological and other problems suffered by the first two. However, these solutions will add to the costs of construction and of operation and maintenance.

2.7 Uncertainties Facing Methanol Development

The uncertainties facing methanol fuel development are of a somewhat different kind than those pertaining to an oil sands project, though no less real. Relative to an oil sands plant, a methanol project is technically much simpler, smaller in size, considerably less expensive and does not require the large front-end investment.

The prime uncertainty with methanol blends is of a technological nature and occurs at the user's end. The lack of experience with the blends used by existing vehicles could translate into a low driver acceptance. Vehicle operators could be apprehensive about using a corrosive substance in their engines. Under certain operating conditions, driveability may also be reduced compared with conventional gasoline. Cold weather starting problems could be encountered, as well as stalling or a reduction in general car performance. These problems may be overcome in time but at the moment, due to the lack of operating experience with methanol blends in Canadian driving conditions, they must be recognized as real.

In terms of financial risks, the main difficulty for methanol producers aiming at the automotive market must be seen in the absence of clear direction in tax treatment of methanol as a fuel. In this respect, however, methanol blends are not unique. Other alternative transportation fuels (e.g., propane or CNG) presently enjoy various tax relief measures but these are generally viewed as temporary and, once discontinued, the economic attractiveness could disappear.

The second financial risk, one which is shared by an oil sands development, relates to the uncertainty found in the world oil market. As methanol blends compete with conventional gasoline for a share in the automotive market, in the absence of government intervention it is ultimately the world price of oil which will determine their economic viability. Thus, should the world price of oil rise in the future, methanol blends will become more cost competitive with gasoline refined from imported oil, and vice versa.

Although the uncertainties facing methanol producers aiming at the automotive market differ from those facing oil sands operators, they must be recognized and taken into consideration before the final choice between the two fuel options at hand is made.

Footnotes

[1]This assumption is based on recent results of methanol/gasoline blend tests in the U.S. Results of one such test were reported in Alcohol Week (September 12, 1983, pp. 8-9), where unmodified test vehicles (mostly 1980 Chevrolet Citations) were specifically tuned for operation on 2 and 4 percent methanol blends with regular gasoline (containing no solvents or additives) by advancing and changing idle settings. In more that 5,000 miles of driving, these cars demonstrated a 20 percent increase in fuel economy; a 15 percent improvement was experienced by a Dodge Dart automobile. In general, the tests showed the blend-vehicle fuel economy exceeding that of the gasoline-powered autos. Also during these tests carried out in San Francisco and Oakland (on behalf of Bank of America) during temperatures as low as 1°C and slightly below freezing, no phase separation was observed. This was attributed to steady reduction of the water concentration in the methanol storage tanks.

Other tests have more typically revealed a slight penalty in fuel economy (between 1 and 5 percent) for methanol/gasoline blends. We have assumed no change between the two fuels with respect to mileage.

More generally, it has become apparent that what seems to matter more than theoretical values for energy content in terms of mileage are driving conditions. Driving on a rich mix, for example, will likely result in no change in mileage between gasoline versus gasoline/ methanol blend. The leaner the mix, however, the greater the possibility of experiencing a small reduction in mileage when driving on gasoline/methanol blend.

[2]Statistics Canada, Refined Petroleum Products, Catalogue 45-004 (Ottawa: Supply and Services Canada, November 1983).

[3]Communication with Interprovincial Pipeline Ltd. in October 1983. Calculated as $\$7.24/m^3$ (NGL tariff) plus a 50 percent premium to cover additional cost and inconvenience of carrying methanol.

[4]Communication with Cochin Pipeline in October 1983. Based on ethane, ethylene and propane tariff of $\$31.83/m^3$ plus a 50 percent premium. These and other assumptions parallel those used in another Institute project related to methanol's use as an automotive fuel. See T. Gibson and W. Haessel, "An Assessment of Benefits and Costs of Using Methanol as a Motor Gasoline Extender in Southern Ontario." Working Paper 84-2 (Calgary: Canadian Energy Research Institute, May 1984).

[5]Energy Pricing News, January 1984 (average annual tariff).

[6]Biewag Energy Resources Ltd., Industrial Development Permit Application and Environmental Impact Assessment, Volume 2, May 1982, p. 43. Natural gas requirements are 994 m^3/tonne of methanol.

Given 1 tonne of methanol = 1.26 m^3 of methanol, then 994 + 1.26 m^3 natural gas required per 1 m^3 of methanol = 789 m^3 of natural gas needed per m^3 of methanol or almost 800 times as much.

[7]Based on 330 stream days of production per year, this provides an annual output of 6.5 x $10^6 m^3$ (41 x 10^6 bbls) of synthetic crude oil.

[8]This production profile reflects Syncrude Canada Ltd.'s production profile experienced over the period 1978-1983. See John R. Lynn, "Syncrude: Five Years of Progress," paper presented to the Conference on Heavy Oil and Tar Sands, Los Angeles, California, November 1983.

Currently, Syncrude Canada is in the process of investing a futher $1.2 billion in order to increase its output to approximately 20,500 m^3/stream day by 1987 (it is assumed that there are 330 stream days per year). This cost estimate, however, includes ongoing capital expenditure for wear and tear over the 5-year expansion period (see same source).

[9]Alberta Department of Industry and Commerce, The Impact of the Syncrude Project on the Economy of Alberta (Edmonton: Hu Harries and Associates, January 1975), pp. 3-4.

[10]Capital cost figures for the methanol plants were estimated from the cost of the Kitimat plant and conversations with industry representatives. The Kitimat plant cost over $200 million but involved significant incremental expenditure due to the remoteness of the location and for earthquake strengthening. Plants built in the three selected locations would be somewhat cheaper.

[11]DataMetrics Limited, An Economic Analysis of Alcohol Fuels and Gasoline From Oil Sands (Toronto: Ontario Ministry of Energy, March 1981), p. 14. This estimate has been converted to constant $1982 using the GNE deflator.

[12]Estimates provided by CERI and industry sources. These are incremental refining cost estimates of producing one cubic metre of refined gasoline from feedstock.

[13]Conversations with chemical industry sources have indicated that the two domestic suppliers of cosolvents would not be able to produce the required amounts without large scale expansion.

[14]Estimates obtained from industry sources as follows. The average cost of domestically produced cosolvent delivered to refineries is about $386/$m^3$, while the price of imported (from the U.S.) cosolvent is $455/$m^3$.

[15]See Canadian Public Policy, Summer 1981. Articles by D. F. Burgess, H. F. Campbell and G. P. Jenkins are particularly relevant.

[16]Bechtel Canada, "Reclaimed Energy, How Canadian Ingenuity Tapped the Athabasca Oil Sands," Bechtel promotional publication.

[17]The basic process was designed by Dr. K. A. Clark of the Alberta Research Council in 1924. The Alsands plant was also designed using the Clark process, but its use was criticized by the Alberta Energy Resources Conservation Board on the basis of low efficiency. See Energy Resources Conservation Board. Alsands Project Group for Approval of an Oil Sands Surface Mining Project. Report 79-H, December 1979

[18]The Globe and Mail, March 1983. At present, a 5-year $1.2 billion investment program is under way at Syncrude to upgrade plant equipment and slightly increase production. By 1987, output should reach approximately 20 x $10^3 m^3$ per calendar day. The $1.2 billion program also includes regular yearly maintenance expenditures.

Chapter 3

EFFECTS OF LEARNING AND PLANT SCHEDULING

3.1 Realized Learning Effects in Construction

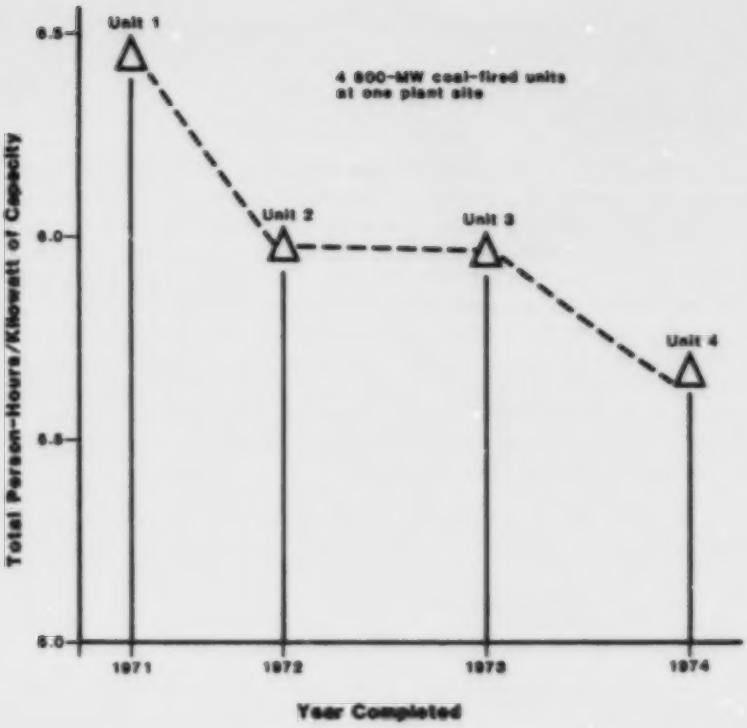
Most of the discussion of the learning curve phenomenon in technical literature has involved learning observed in manufacturing industries (see Appendix B, Section B.4). A similar effect has been observed in other industries such as construction. Kennedy and Allen observed that a learning effect resulted in reduction of construction costs on subsequent generation units built for Detroit Edison at Monroe, Michigan.[1] This plant was composed of four virtually identical 800-megawatt generating units. The authors found that the learning curve effect resulted in a saving of 1.65 million man-hours for the second through fourth units (with a value of about $45 million U.S.). This amounted to about an average 5 percent decrease in cost per unit from the second unit on (see Figure 3.1).

Kennedy and Allen suggest that in order for this learning effect to occur:

- successive units must be similar;
- technological changes must be transferable; and
- there must not be great disruptions in personnel, location, or other manufacturing circumstances.

The following factors have been cited as being important for learning during the construction of power plants:

- improved tooling;
- method improvements and work simplifications;
- effective design modifications;
- improved scheduling;
- product quality improvements;
- operator learning; and
- improved communications.



SOURCE: W.J.Kennedy and C.R.Allen, POWER ENGINEERING.

FIGURE 3.1: PLANT PERSON-HOURS

In turn these factors can result from familiarity between labour and management groups, contractor-labour union rapport, and general community rapport. One important source of efficiency gain can come from improved owner-contractor rapport. Late delivery of materials, materials that do not fit specifications, or design changes that result in modification of part of the project can be eliminated or at least reduced through improved owner-contractor rapport.

Other contributing factors are better schedule coordination, increased staff continuity, reduced staff turnover, and better knowledge of requisite permit procedures for the project.

To the extent that repeated construction of methanol plants satisfies the conditions described above as conclusive to the realization of learning curve type cost savings, it is assumed that these savings will be realized in construction of three (or more) methanol plants.

It has been shown that enough evidence exists to suggest that the learning curve phenomenon does exist, that it could bring about cost reductions and that it could be applied to methanol plant construction. However, evidence also suggests that the extent of efficiency improvements which can be produced varies considerably. For the purpose of this project it is necessary to estimate the characteristics of the learning curve relevant to the construction of three methanol plants of 480,000 cubic metre output capacity per year. Could it be assumed that our learning curve would resemble the "power plant learning curve" mentioned above?

3.2 Learning Curve Applications to Methanol Plants

Careful documentation of the learning curve effects experienced in manufacturing industries and some construction projects would seem to be good evidence for important cost reductions in repeated construction of virtually identical methanol plants. These cost reductions could be important factors in reducing the supply price of methanol produced from these plants.

However, upon closer inspection of the mechanics of planning, contract-awarding and constructing of methanol or any other plants, it is clear that even plants producing the same output will not be

strictly identical. Important differences will originate with plant location, layout, source and quality of feedstock, etc. The Ocelot plant at Kitimat, B.C. for example, required special structural engineering because it lies in an earthquake-prone area. This type of modification would not be required in Alberta or Ontario, although others might. Plants built in remote locations might possibly require an extension of services such as roads, pipelines, electrical grid connections, water supply, and the like.

One potential source of significant cost saving applicable to the methanol project is in the managerial area. Conversations with industry representatives have suggested that if the same engineering group designed and built the plants, one after another, cost savings of 1 to 2.25 percent might be possible on second and later plants. However, a major problem with this assumption lies in the necessity of using a competitive bidding process. In Canada there are several (seven to ten) engineering companies which have the capability to design and build methanol plants and most of these would eagerly want to bid on any available projects. If one company were to be continuously awarded the contract, this would constitute a distinct departure from current procurement practices. The same problem would also arise in the procurement of machinery and equipment where alternate suppliers expect an open bidding process on sub-contract deliveries. Some large components used in the Kitimat plant were imported. This could not be expected to continue with many subsequently built plants. These considerations would tend to mitigate against significant cost reductions being effected with each incremental plant built. When considering construction of more than one methanol plant, it may therefore be unrealistic to assume significantly reduced costs on subsequent plants, given the Canadian construction and procurement environment.

On the other hand, the French experience from repeatedly constructing identical nuclear power plants suggests that a cost reduction of about 1 percent per each subsequent plant is possible. These construction cost savings, however, are believed to be the result of a single central engineering contractor responsible for the ongoing nuclear plant construction.[2]

In spite of these qualifications, it is useful to evaluate the potential reduction in supply prices of methanol if a string of plants were subject to the learning curve effects manifest in the total cost equation given in the previous section.

3.3 A General Formulation of Learning Effects in Plant Construction

A study for the U.S. Department of Energy entitled "Some Exploratory Consideration of Scale Effects on the Potential Performance of Wood Energy Conversion Systems" evaluated the learning curve effects which might be exhibited in wood-to-methanol conversion plants.[3] Although this type of plant is somewhat more complex than the natural gas-to-methanol plant considered here, especially in the feedstock handling division, it is nevertheless close in design to the plant type under study and, as such, the learning curve may be considered as a good approximation.

The above-mentioned study postulates a mathematical relationship between total costs and the number of plants constructed. The formulation is essentially:

$$TC_N = TC_1 \left(\frac{1}{N}\right)^m$$

where TC_1 is the cost of the first plant, N is the number of subsequent plants, and m is the observed cost exponent.[4]

In the following section a value of 0.1 is suggested for the value of m which, more generally, should be within $0 < m < 0.25$. For the purpose of sensitivity analysis, the value of 0.2 has also been assigned to m .[5] Using these values a matrix of cost reductions can then be generated for any number of plants. As an illustration, ten plants have been chosen with the reduction constants as shown in Table 3.1.

The constants for $m = 0.1$ and $m = 0.2$ are graphically depicted in Figure 3.2 to obtain learning curves. It may be seen that for $m = 0.1$, the percentage reduction in cost between successive plants declines with increased quantity constructed. The second plant is 7 percent cheaper to build than the first but the fifth plant is only 2 percent cheaper than the fourth. By the time the tenth plant is constructed the incremental saving over the cost of the ninth plant is only about 1 percent. Ultimately, however, the tenth plant is about 21 percent cheaper to build than the first.

TABLE 3.1

COST FACTOR WITH LEARNING CURVE EFFECTS

Plant	Cost Factor for $m = 0.1$	Cost Factor for $m = 0.2$
1	$(1/1)^{.1} = 1.00$	$(1/1)^{.2} = 1.00$
2	$(1/2)^{.1} = 0.93$	$(1/2)^{.2} = 0.87$
3	$(1/3)^{.1} = 0.90$	$(1/3)^{.2} = 0.80$
4	$(1/4)^{.1} = 0.87$	$(1/4)^{.2} = 0.76$
5	$(1/5)^{.1} = 0.85$	$(1/5)^{.2} = 0.72$
6	$(1/6)^{.1} = 0.84$	$(1/6)^{.2} = 0.70$
7	$(1/7)^{.1} = 0.82$	$(1/7)^{.2} = 0.68$
8	$(1/8)^{.1} = 0.81$	$(1/8)^{.2} = 0.66$
9	$(1/9)^{.1} = 0.80$	$(1/9)^{.2} = 0.64$
10	$(1/10)^{.1} = 0.79$	$(1/10)^{.2} = 0.63$

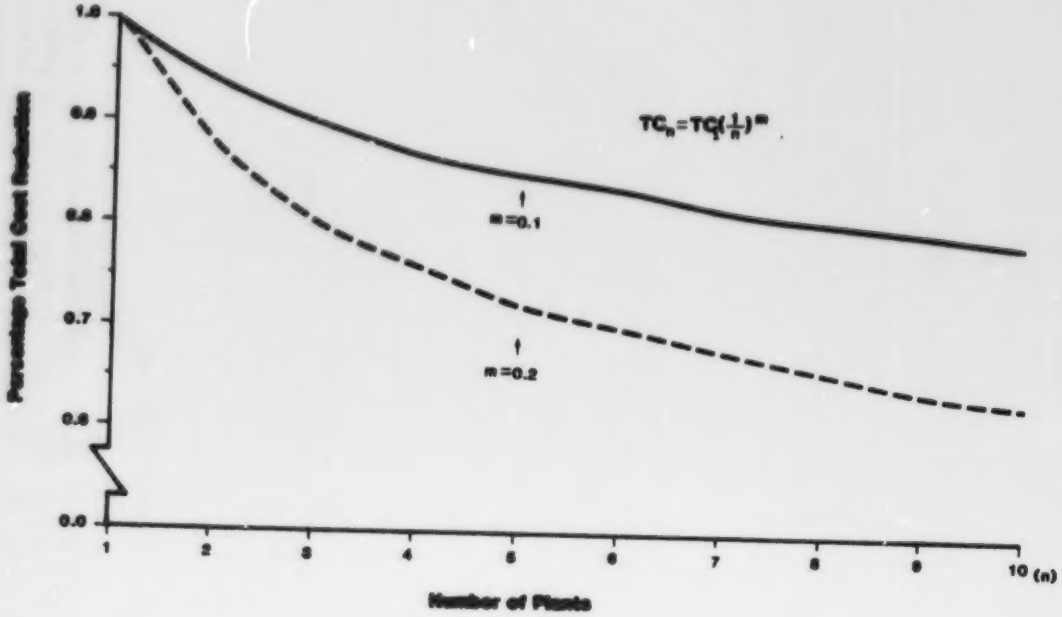


FIGURE 3.2: LEARNING CURVE FACTORS

The above-mentioned study by Eggers et al. concluded that the effect of the learning curve on costs of methanol-from-wood plants would reduce total costs by less than 15 percent for a population of 100 conversion plants. This same study makes the point that the cost reductions resulting from the learning curve effect will probably be relatively weaker than those anticipated from economies of scale by increasing the capacity of each single plant.[6] It should be noted that the methanol-from-natural gas plants under study have a gross output capacity of 480 x $10^3 m^3$/yr. For comparison purposes, the largest methanol plant of this type in the world, the Celanese Canada unit at Clover Bar, Alberta is rated at 994 x $10^3 m^3$/yr. This is significantly larger than the representative plant used for this study. However, industry representatives have suggested that increasing the scale of the plant would have little effect on unit costs. The next section details the estimation of supply prices for methanol utilizing the learning curve cost reduction factors given above.

For comparison purposes, assume that five plants are built: the first one in Alberta, the next two in Ontario, and the fourth and fifth in the Montreal area. The plant construction costs and cost reduction factors are shown in Table 3.2. Using these capital cost estimates and other cost estimates from Section 2.4, supply prices for each plant have been calculated. These are shown in Table 3.3. It should be noted that these estimates also include make-up gasoline costs as in previously derived estimates.

The methanol supply prices vary due to locational differences (e.g., feedstock costs) but also due to the learning effects. For example, the third plant built is in the same area as the second but is able to supply energy at $\$0.38/m^3$ cheaper than the second (for m = 0.1 and 10 percent discounting). The fifth plant can supply energy at $\$0.25/m^3$ cheaper than the fourth (for m = 0.1 and 10 percent discounting) even though they are both built in Quebec. These are unit cost reductions of 0.138 percent and 0.092 percent, respectively, due exclusively to learning effects.

3.4 Scheduling and Cost-Effectiveness of Cases

There are various ways of scheduling the construction of either the methanol or the synthetic oil plants which will have an effect on the stream of costs, and thus profitability. The effects of different scheduling are examined in this section. Four cases are analyzed which

TABLE 3.2

METHANOL PLANT CONSTRUCTION COSTS
WITH LEARNING CURVE EFFECTS
(millions of $1982)

Plant	Small Learning Curve Effects (m = 0.1)[a]		Large Learning Curve Effects (m = 0.2)[a]		Plant Location
	Cost Factor	Plant Cost	Cost Factor	Plant Cost	
1	1.00	135 (180)[b]	1.00	135 (180)[b]	Alberta
2	0.93	171	0.87	159	Ontario
3	0.90	166	0.80	148	Ontario
4	0.87	160	0.76	140	Quebec
5	0.61	156	0.72	131	Quebec

[a]These values are consistent with the efficiency gains implied by A. J. Eggers et al.; see footnote 3.

[b]The value in brackets is the full cost of the Alberta plant. Note that the values for the Alberta plant are otherwise based on only that amount of output dedicated to fuel use (73 percent).

TABLE 3.3

METHANOL SUPPLY PRICES WITH LEARNING CURVE EFFECTS[a,b]
($/m^3 of gasoline equivalent)

Plant	Discount Rate (m = 0.1)			Discount Rate (m = 0.2)		
	5%	10%	15%	5%	10%	15%
1	274.81	269.52	267.64	274.81	269.52	267.64
2	282.17	274.75	269.90	281.54	273.87	268.83
3	281.86	274.37	269.40	280.85	272.92	267.70
4	280.66	271.66	265.06	279.59	270.34	263.61
5	280.47	271.41	264.74	279.15	269.78	262.92

[a]It should be noted that supply prices rise with subsequent plants due to higher feedstock and refining costs in Ontario and Quebec.

[b]The Option Supply Price With Learning Effects shown in Table 2.2 is a volume weighted average of the first three plants shown in this table (for m = 0.2).

are examples of options available to satisfy a given demand for motor fuel.

3.4.1 Case 1: Synthetic Crude Oil

The first case is to construct, starting in 1975, and operate a synthetic oil plant and refine the syncrude in Edmonton, Sarnia and Montreal for three major Canadian motor fuel markets. The costs incurred in choosing this route would be the construction and operation of the plant, pipeline charges to ship the oil to Edmonton, Sarnia and Montreal, and refining charges in those centres.[7] Also incurred would be the cost of importing crude oil and refining it while the synthetic oil plant is being constructed and brought fully on stream. Crude oil used in Toronto and Alberta markets to produce make-up gasoline costs less (by transportation margins) than in Montreal.

Refining charges are based on a sharing of the synthetic oil output in the three centres. When the oil sands plant is fully on stream, 26 percent of the oil is refined in Edmonton, 37 percent in the Toronto area and 37 percent in Montreal. Refining charges are assumed to be \$63/m^3 in Ontario and Quebec and \$47/m^3 of gasoline in Alberta. Refining charges differ between regions because Alberta refineries are generally newer, more efficient and have lower fuel costs. Before synthetic oil is available, conventional domestic oil is assumed to be used in Alberta and Ontario, and imported oil in Quebec. Values for imported crude oil are shown in Table A.7. Costs for all oil have been reduced by 55 percent to account for other refined products as explained above.

The present value of the synthetic gasoline from the oil sands option has been evaluated by determining the present value of the oil sands development first. To apply a joint product credit, this value has been reduced by 55 percent as explained in Section 2.3. To this amount has been added the present value of the costs of make-up gasoline, refining charges and oil transportation. All these costs have been evaluated at three different discount rates. The present value of the cost stream of supplying approximately 2.6 x $10^6 m^3$ of synthetic gasoline annually for 29 years is shown in Table 3.4 for three different discount rates.

3.4.2 Case 2: Simultaneous Methanol Plants

The next alternative is to build three methanol plants simultaneously in Alberta, Ontario and Quebec. The three plants are all started in 1975 and completed in 1976 with all three plants going on stream in 1977 at 100 percent of capacity. Thus, in 1977 the output of the three plants, plus the required cosolvent additive, satisfies the given demand. Oil is required only in 1975 and 1976 to yield gasoline during the construction period and also after the lifespan (20 years) of the methanol plants is exhausted. Because the three plants are all started simultaneously it is presumed that learning curve effects do not take place.

The cost stream of this option, and the following two, includes the capital and operating costs of the methanol plants, the cost of the required cosolvent to be blended with it and the cost of importing (or using conventional domestic oil in place of imports) and refining crude oil to gasoline when methanol is not being produced.

3.4.3 Case 3: Early Sequential Methanol Plants

A third alternative assumes that the construction of the methanol plants is staggered so that when the first is completed, the second begins construction and similarly with the third. This would allow contractors and construction crews to move to the new site and to carry their experience with them. Therefore, learning curve effects are assumed in this option (i.e., for $m = 0.2$).

Due to the delay in producing full output from the three methanol plants, the charges for imported oil are greater in the early years of the project. Sequencing of the plants occurs such that the Alberta plant is built in 1975-1976 and comes on stream in 1977, the Ontario plant is built in 1977-1978 and comes on stream in 1979, and the Quebec plant is built in 1979-1980 and comes on stream in 1981.

3.4.4 Case 4: Delayed Sequential Methanol Plants

A variation of the previous case involves delaying construction of all methanol plants by 2 years. They will still be built

sequentially, only 2 years later in order that the full methanol production from all three plants roughly coincides with full capacity output from the oil sands plant. Construction of the Alberta plant starts in 1977 and it goes on stream in 1979. The Ontario plant is built in 1980-1981 and the Quebec plant is built in 1982-1983.

3.4.5 Conclusions

Table 3.4 and Figure 3.3 show the present value of the costs of the four specified cases designed to show the effect of different scheduling of the construction periods of synthetic crude oil and methanol plants. These results indicate that the discount rate is a very critical variable in determining which of the four cases is the least expensive. At 5 percent discounting the synthetic gasoline option is the least expensive. If the discount rate chosen is 10 percent, the least expensive option is to build the methanol plants sequentially (Case 3). At 15 percent discounting the oil sands option (Case 1) is the most expensive, while Case 3 (sequential methanol plants) remains the cheapest option.

The importance of comparing two options having the same annual output of gasoline equivalent for all the years of the longest option appears from Table 3.4. If the costs of make-up gasoline from imported crude was not added for the last 5-9 years of the methanol cases, the oil sands option would have appeared less attractive.

3.5 Regional Impacts of Domestic Fuel Production

The production of synthetic gasoline or a methanol-cosolvent blend will both enlarge the domestic gasoline pool significantly and reduce imports of oil.

If either of the two fuel options were pursued, approximately 2.6 million cubic metres of gasoline would be displaced each year in Canada. Approximately 37 percent of this (960,000 m^3) would be displaced in each of the Ontario and Quebec markets, while about 26 percent (700,000 m^3) would be displaced in the Alberta market. This would correspondingly extend the lifespan of conventional oil reserves in Western Canada.

Alternatively, the increased production of gasoline or blended fuel could be used to back more imports of oil out of the Eastern

TABLE 3.4

PRESENT VALUE OF COSTS FOR ALTERNATIVE SUPPLY CASES
($1982 x 10^9)

Discount Rate (%)	Case 1 Synthetic Crude Oil	Case 2 Simultaneous Methanol Plants	Case 3 Early Sequential Methanol Plants	Case 4 Delayed Sequential Methanol Plants
5	9.96	11.33	11.10	11.14
10	6.87	6.89	6.71	6.76
15	5.24	4.79	4.62	4.65

NOTES: Cost of oil from synthetic oil plant is evaluated at 46 percent of total cost to credit for joint products. Cases 3 and 4 include a learning exponent of m = 0.2. The present value of importing an equivalent amount of energy is $12.3 billion at 5 percent discounting, $7.3 billion at 10 percent and $4.9 billion at 15 percent discounting.

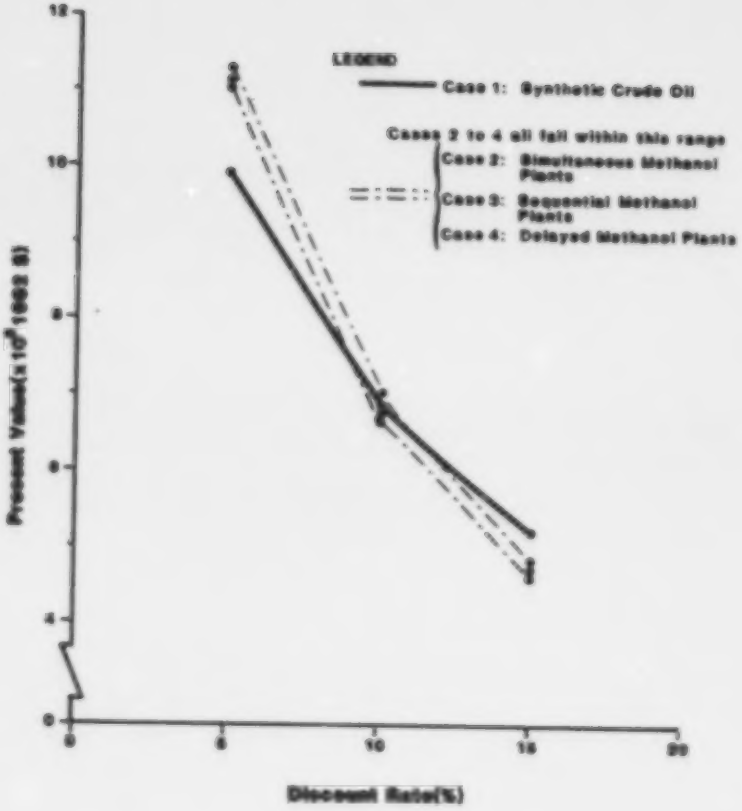


FIGURE 8.9: PRESENT VALUE OF COSTS FOR EACH CASE

Canadian market. The entire production of fuel of either option (2.6 million cubic metres per year) would have accounted for 35 percent (in an unblended form) of the Canadian motor gasoline market supplied by imported crude oil (Atlantic Canada and Quebec) in 1982.[8]

Footnotes

[1]W. J. Kennedy and C. R. Allen, "Learning Curves as Applied in Power Plant Construction," Power Engineering, September 1979, pp. 63-65.

[2]See Uranium and Nuclear Energy: 1982, Proceedings of the Seventh International Symposium held by the Uranium Institute, London, September 1982, pp. 161-176.

[3]U.S. Department of Energy, Office of Solar Applications for Industry, Some Exploratory Considerations of Scale Affects on the Potential Performance of Wood Energy Conversion Systems by A. J. Eggers, Bruce A. Smith and Larry W. Tombough. Contract Number DE-AC03-81ET20651, June 1982.

[4]Ibid., pp. 23-28.

[5]Ibid., p. 25.

[6]Ibid., p. 26.

[7]Pipeline charges are approximately $7.00/m^3$ to ship oil to Toronto from Edmonton and $7.60/m^3$ to ship oil to Montreal. It has been assumed that these charges will remain constant in real terms.

[8]Statistics Canada, Refined Petroleum Products, Catalogue 45-004 (Ottawa: Supply and Services Canada, October 1983).

Chapter 4

REGIONAL ANALYSIS

4.1 Introduction

The purpose of this chapter is to determine and compare national and regional economic impacts of constructing a Syncrude-type oil sands plant in Northern Alberta and constructing methanol plants in Alberta, Ontario and Quebec. Operation of these plants is excluded. Using Statistics Canada's 1974 version of the Interprovincial Input-Output Model, interregional income and employment impacts are calculated.[1] The model delineates economic activity in terms of income and employment at both the provincial and national levels. Income is the most comprehensive indicator of economic welfare used in assessing macroeconomic impacts. Employment impacts are significant because jobs are of special concern to policy makers, particularly during times of high unemployment.

Input-output analysis decomposes the economic impact into three effects: direct, indirect and induced.

- Direct effects are those which involve particular industries whose output is directly stimulated by the project expenditures.
- Indirect effects occur in those industries that supply inputs to the industries directly stimulated and also the subsequent effects of supplying these industries, etc.
- Induced effects are the increase in economic activity generated by the spending of household income (wages, salaries, supplementary labour income and net income of unincorporated business).

Input-output techniques allow decision makers to formulate policy according to national and regional economic impacts. However, it cannot be used to rank projects or assess project feasibility. A benefit-cost analysis is necessary to address these issues.

The analysis presented in this section is based on the following assumptions: construction of a 20 x $10^3 m^3$/day oil sands plant in Northern Alberta and construction of three identical methanol facilities producing approximately 480 x $10^3 m^3$/yr of methanol. The methanol plants are located in Alberta, Ontario and Quebec. All income and expenditures in this chapter are reported in 1974 dollars and employment impacts are based on 1974 job/output ratios. The income measure used is gross domestic product at market prices and employment impacts are reported in terms of person-years. All data used in this chapter and their sources are detailed in Appendix Tables A.12 to A.15.

4.2 Economic Impact of Plant Construction

4.2.1 Oil Sands Plant

Figures 4.1 and 4.2 depict the impacts on income and employment of constructing a $4.0 billion oil sands plant in Alberta. The impact on income of $2.2 billion occurs primarily in three provinces. Alberta garners 50 percent of the increased income; the Ontario and Quebec shares are 28 and 12 percent, respectively (see Table 4.1). As expected, most of the direct income generated is in Alberta because of the location of the plant. However, the indirect effects are greatest in Ontario because of the location of many goods-supplying industries in that province.

TABLE 4.1

REGIONAL DISTRIBUTION OF ECONOMIC IMPACTS
OF THE OIL SANDS PLANT
(percent)

	Atlantic Canada	Quebec	Ontario	Alberta	Other Western Provinces	Canada
Income	2.0	11.6	28.1	50.0	8.3	100.0
Employment	2.2	13.7	30.9	44.9	8.3	100.0

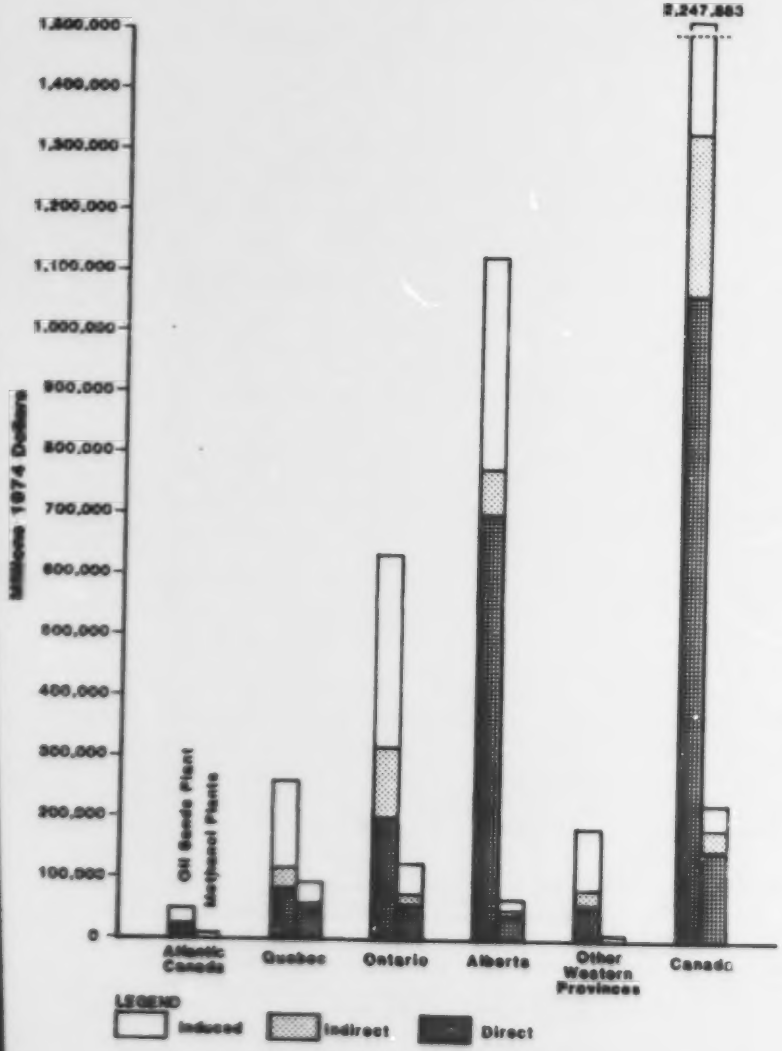


FIGURE 4.1: IMPACT ON INCOME

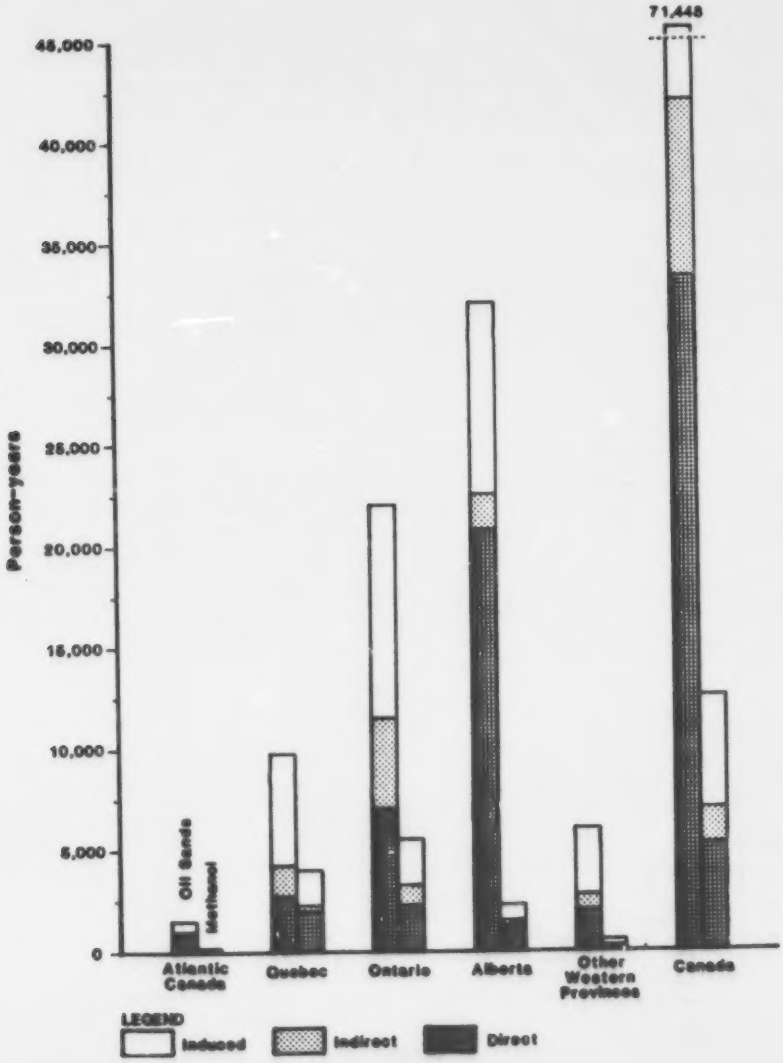


FIGURE 4.2: IMPACT ON EMPLOYMENT

The breakdown of the regional impact on employment is similar with nearly one half of the project's total manpower requirements of around 71,400 person-years being drawn from the Alberta labour force and nearly a third from that of Ontario.

4.2.2 Methanol Plants

Figures 4.1 and 4.2 show the regional income and employment imports resulting from construction of the methanol plants. As was the case with the oil sands plant, the impacts occur primarily in the province in which they are constructed.

Figure 4.3 shows that construction of the three methanol plants at a cost of $184 million each generates national income of almost $300 million of which 43 percent accrues to Ontario, 31 percent to Quebec and 22 percent to Alberta. Indirect economic impacts are largest in Ontario, reflecting its role as a primary supplier of goods.

The largest share of workforce requirements are drawn from Ontario. Of the total 12,400 man-years of employment generated, Ontario, Quebec and Alberta obtain 45 percent, 32 percent and 18 percent of the impact, respectively.

When examined individually, the national economic impact of each plant is similar with each plant generating income of about $100 million and about 4,000 person-years of employment in Canada. The difference in provincial income and employment impacts, however, is pronounced. Figure 4.3 shows that an Ontario based methanol plant generates a larger intraprovincial economic impact than a plant located in either Quebec or Alberta. Ontario also benefits significantly from projects based outside of Ontario, receiving the largest spin-off effects next to the province of construction (see Table 4.2). On the other hand, Western Canada accounts for only 4 percent of the national income generated by an Ontario or Quebec based methanol plant. The impact in Atlantic Canada is very small for a methanol plant located in any of the three provinces.

The regional distribution of employment impacts is similar to the impacts on income and is shown in Figure 4.2.

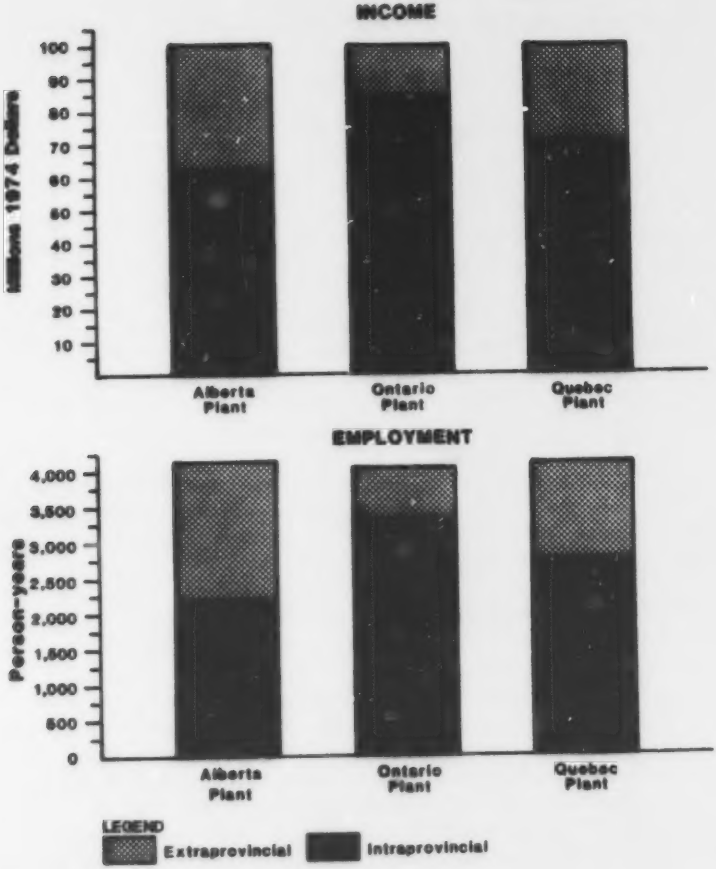


FIGURE 4.3: ECONOMIC IMPACTS OF INDIVIDUAL METHANOL PLANTS

TABLE 4.2

REGIONAL DISTRIBUTION OF ECONOMIC IMPACTS
OF METHANOL PLANT CONSTRUCTION
(percent)

	Atlantic Canada	Quebec	Ontario	Alberta	Other Western Provinces	Canada
INCOME						
Alberta Plant	0.4	10.2	21.0	63.0	5.4	100.0
Ontario Plant	0.6	11.1	84.2	2.3	1.8	100.0
Quebec Plant	0.8	71.4	24.4	1.7	1.7	100.0
TOTAL	0.6	30.8	43.2	22.4	3.0	100.0
EMPLOYMENT						
Alberta Plant	0.6	14.2	26.2	52.7	6.3	100.0
Ontario Plant	1.0	15.4	81.0	0.9	1.7	100.0
Quebec Plant	1.3	66.6	29.5	1.0	1.6	100.0
TOTAL	1.0	32.1	45.4	18.3	3.2	100.0

4.3 Summary

An oil sands project shows a significantly greater impact on the economy than three methanol plants. This result should not be surprising because the oil sands plant capital expenditures are extremely large relative to the methanol alternative. The results indicate that an oil sands project would generate national income of over $2.2 billion compared with around $300 million for three methanol plants. In terms of employment, the oil sands project would generate about 71.4 thousand person-years of employment in Canada, compared with around 12.4 thousand person-years of employment derived from the methanol plants. The very large employment effect obtained from constructing the oil sands plant, again clearly reflects the significantly greater size of the plant and its longer construction period relative to those of the methanol plants.

Footnotes

[1]Gordon W. Douglas and James A. MacMillan, Interregional Economic Impacts of the Alberta Alsands Project, Client Research Report 82-2 (Calgary: Canadian Energy Research Institute, September 1982).

Chapter 5
CONCLUSIONS

5.1 Supply Prices of the Two Fuel Options

The construction and operation of either an oil sands plant or several methanol plants have been set in the broader perspective of meeting a demand for motor fuel equal to the refined output of the oil sands project. Included in the analysis is the cost of an alternative source of gasoline while the oil sands or methanol plants are being constructed and brought fully on stream. Resulting unit supply prices for both options have been estimated at three different discount rates and are shown in Figure 2.5, where a supply price is defined as the minimum price that accounts for both capital and operating costs at which a producer would proceed with production, excluding all taxes and royalties. In turn, the rate of discount can be viewed in the usual manner where it stands for the minimum rate of return needed to cover the opportunity cost of capital invested. Three methanol plants are required and the analysis includes the cost of methanol as well as the cost of cosolvent needed for a one-to-one methanol/cosolvent blend.

It can be seen in Figure 2.5 that the methanol supply prices do not exhibit much sensitivity to a changing discount rate, to which the synthetic gasoline option is highly sensitive. This difference originates with the large variation of operating cost outlays and time profiles for the two fuel options. At a real rate of 10 percent, synthetic gasoline is about 4 percent more expensive than methanol produced in Alberta. At a real rate of 15 percent, however, all methanol plants can produce motor fuel more cheaply, and if average values of all three methanol plants are compared with the supply price of synthetic gasoline, the latter is more expensive by about 10 percent. When assumed learning curve effects are allowed for, the methanol option supply price at a 15 percent discount rate is about 13 percent cheaper than that of synthetic gasoline. However, it has been suggested that a median for the social rate of discount appropriate for this analysis is between 7 and 10 percent. Thus, given all other assumptions employed, the synthetic gasoline option is cheaper than the

methanol option at the lower end of this range, while methanol becomes the preferred option at rates above approximately 8.5 percent.

5.2 Uncertainties Facing Oil Sands and Methanol Developments

There are many uncertainties facing both the oil sands and methanol fuel options which may result in significant impacts on either project. While an oil sands development may be expected to experience difficulties related to its size, large front-end loaded investment, bitumen recovery technology which needs improvement, and complicated logistics, methanol blends may face reduced driveability and lower driver acceptance. Both fuel options may further be affected by largely unpredictable developments in the world oil market, whereby a weakening price of oil will lessen the economic attractiveness of both. Uncertainty has negative effects on the attractiveness of the oil sands alternative because the initial capital cost is seven times the capital cost of the methanol alternative.

5.3 Estimates of Present Values of Total Option Costs

An interesting analysis can be undertaken of the present values of total costs of synthetic gasoline versus the methanol blend. A single oil sands plant will have a construction and operation time profile quite different from that of three methanol plants. The present value of total costs of building three methanol plants will be affected by the particular pattern of bringing the three plants on stream. Four cases have been investigated. The first refers to the oil sands alternative for comparison. The second to fourth cases refer to the construction and operation of three methanol plants, with the timing of construction varied in each case. The second case involves construction of the three plants simultaneously; the third case refers to construction of the methanol plants sequentially and includes the learning curve effect; and the fourth case delays sequential construction of the three methanol plants by 2 years in order to bring the full methanol output from the three plants on stream at roughly the same time as the full capacity output from the oil sands plant. Figure 3.3 shows the present values of total cost of the four cases at three discount rates. At a low discount rate (5 percent), the oil sands project is the least expensive. However, at a higher discount rate (15 percent), the oil sands project becomes the most expensive. As the discount rate increases beyond about 8 percent, the present value of

total cost of the oil sands option becomes progressively higher relative to that of the methanol option.

5.4 Learning Curve Effects

One objective of this study has been to investigate the effect of learning on costs through repeated construction of identical methanol plants. Based on related available experience, a certain learning curve as applied to plant construction cost has been postulated and the effect of repeated construction on supply prices estimated. The results show that, given other assumptions, the supply prices for the methanol option vary by less than 0.2 percent in response to moderately lower capital construction costs. The conclusion is that learning curve effects cannot be expected to bring about significant methanol supply price reductions in the case of repeated construction of three identical methanol plants.

5.5 Regional Impacts of Plant Construction

Analysis of the regional impacts on employment and income between the construction phases of the two fuel options indicates significantly greater effects of an oil sands plant relative to three methanol plants. This result should not be surprising, because the initial capital cost of the oil sands plant is extremely large relative to the methanol alternative.

The results indicate that the construction of an oil sands plant would generate additional national income about seven times greater that of the three methanol plants taken together. In terms of employment, an oil sands project would generate approximately six times as many person-years as the methanol plants.

APPENDIX A
DETAILED DATA TABLES

TABLE A.1

SYNTHETIC OIL PLANT COSTS AND OUTPUT

Year	Capital Cost ($1982 x 10^6)	Operating Cost ($1982 x 10^6)	Output ($10^6 m^3$/yr)	Output (10^6bbls/yr)
1975	1 304	0	0	0
1976	1 152	0	0	0
1977	884	0	0	0
1978	568	0	0.48	3
1979	68	400	1.59	10
1980	0	500	3.65	23
1981	0	500	4.13	26
1982	0	600	4.77	30
1983	0	600	5.24	33
1984	0	600	6.50	41
1985	0	600	6.50	41
1986	0	600	6.50	41
1987	0	600	6.50	41
1988	0	600	6.50	41
1989	0	600	6.50	41
1990	0	600	6.50	41
1991	0	600	6.50	41
1992	0	600	6.50	41
1993	0	600	6.50	41
1994	0	600	6.50	41
1995	0	600	6.50	41
1996	0	600	6.50	41
1997	0	600	6.50	41
1998	0	600	6.50	41
1999	0	600	6.50	41
2000	0	600	6.50	41
2001	0	600	6.50	41
2002	0	600	6.50	41
2003	0	600	6.50	41

SOURCES: (1) Hu Harries and Associates Ltd., The Impact of the Syncrude Project on the Economy of Alberta, prepared for the Government of Alberta, 1975; and (2) industry estimates.

TABLE A.2

ALBERTA METHANOL PLANT COSTS AND OUTPUT

Year	Capital Cost ($1982 x 10^6)	Operating Cost ($1982 x 10^6)		Output ($10^3 m^3$/yr)	Output (10^6bbls/yr)
		Non-Fuel	Feedstock		
1975	53	0	0	0	0
1976	82	0	0	0	0
1977	0	22	7	350	2.2
1978	0	22	8	350	2.2
1979	0	22	8	350	2.2
1980	0	22	9	350	2.2
1981	0	22	9	350	2.2
1982	0	22	10	350	2.2
1983	0	22	12	350	2.2
1984	0	22	12	350	2.2
1985	0	22	12	350	2.2
1986	0	22	12	350	2.2
1987	0	22	13	350	2.2
1988	0	22	13	350	2.2
1989	0	22	12	350	2.2
1990	0	22	13	350	2.2
1991	0	22	14	350	2.2
1992	0	22	14	350	2.2
1993	0	22	14	350	2.2
1994	0	22	15	350	2.2
1995	0	22	15	350	2.2
1996	0	22	15	350	2.2
1997	0	0	0	0	0
1998	0	0	0	0	0
1999	0	0	0	0	0
2000	0	0	0	0	0
2001	0	0	0	0	0
2002	0	0	0	0	0
2003	0	0	0	0	0

SOURCES: Industry and CERI estimates.

NOTE: Transportation costs for materials for the Alberta plant are negligible. Output figures have been rounded. Capital cost for 1976 includes the $4 million ($1982) for the cosolvent storage (see Section 2.5.2).

TABLE A.3

ONTARIO METHANOL PLANT COSTS AND OUTPUT

Year	Capital Cost ($1982 x 10^6)	Operating Cost ($1982 x 10^6)		Output ($10^3 m^3$/yr)	Output (10^6bbls/yr)
		Non-Fuel	Feedstock		
1975	72	0	0	0	0
1976	112	0	0	0	0
1977	0	30	23	480	3.0
1978	0	30	25	480	3.0
1979	0	30	25	480	3.0
1980	0	30	25	480	3.0
1981	0	30	25	480	3.0
1982	0	30	27	480	3.0
1983	0	30	30	480	3.0
1984	0	30	30	480	3.0
1985	0	30	30	480	3.0
1986	0	30	30	480	3.0
1987	0	30	31	480	3.0
1988	0	30	31	480	3.0
1989	0	30	31	480	3.0
1990	0	30	32	480	3.0
1991	0	30	32	480	3.0
1992	0	30	33	480	3.0
1993	0	30	33	480	3.0
1994	0	30	34	480	3.0
1995	0	30	34	480	3.0
1996	0	30	34	480	3.0
1997	0	0	0	0	0
1998	0	0	0	0	0
1999	0	0	0	0	0
2000	0	0	0	0	0
2001	0	0	0	0	0
2002	0	0	0	0	0
2003	0	0	0	0	0

SOURCES: Industry and CERI estimates.

NOTE: Output figures have been rounded.

TABLE A.4

QUEBEC METHANOL PLANT COSTS AND OUTPUT

Year	Capital Cost ($1982 x 10^6)	Operating Cost ($1982 x 10^6)		Output ($10^3 m^3$/yr)	Output (10^6bbls/yr)
		Non-Fuel	Feedstock		
1975	72	0	0	0	0
1976	112	0	0	0	0
1977	0	30	26	480	3.0
1978	0	30	28	480	3.0
1979	0	30	28	480	3.0
1980	0	30	29	480	3.0
1981	0	30	29	480	3.0
1982	0	30	30	480	3.0
1983	0	30	34	480	3.0
1984	0	30	34	480	3.0
1985	0	30	34	480	3.0
1986	0	30	34	480	3.0
1987	0	30	34	480	3.0
1988	0	30	34	480	3.0
1989	0	30	34	480	3.0
1990	0	30	34	480	3.0
1991	0	30	36	480	3.0
1992	0	30	36	480	3.0
1993	0	30	36	480	3.0
1994	0	30	37	480	3.0
1995	0	30	37	480	3.0
1996	0	30	38	480	3.0
1997	0	0	0	0	0
1998	0	0	0	0	0
1999	0	0	0	0	0
2000	0	0	0	0	0
2001	0	0	0	0	0
2002	0	0	0	0	0
2003	0	0	0	0	0

SOURCES: Industry and CERI estimates.

NOTE: Output figures have been rounded

TABLE A.5

NATURAL GAS FEEDSTOCK PRICES

Year	1982 $/m^3			1982 $/gigajoule		
	Alberta	Ontario	Quebec	Alberta	Ontario	Quebec
1975	0.021	0.056	0.065	0.56	1.50	1.74
1976	0.023	0.058	0.067	0.61	1.55	1.79
1977	0.025	0.061	0.070	0.67	1.62	1.85
1978	0.029	0.065	0.073	0.78	1.72	1.96
1979	0.029	0.065	0.073	0.78	1.72	1.96
1980	0.032	0.067	0.076	0.84	1.79	2.02
1981	0.031	0.066	0.075	0.82	1.77	2.00
1982	0.035	0.070	0.079	0.92	1.86	2.10
1983	0.045	0.080	0.089	1.19	2.13	2.37
1984	0.043	0.079	0.088	1.15	2.10	2.33
1985	0.043	0.078	0.087	1.14	2.09	2.32
1986	0.044	0.079	0.088	1.17	2.12	2.35
1987	0.045	0.080	0.089	1.20	2.14	2.38
1988	0.046	0.082	0.090	1.23	2.17	2.41
1989	0.045	0.080	0.089	1.19	2.13	2.37
1990	0.048	0.084	0.092	1.29	2.23	2.46
1991	0.049	0.085	0.094	1.31	2.26	2.49
1992	0.051	0.086	0.095	1.35	2.29	2.53
1993	0.052	0.087	0.096	1.38	2.32	2.56
1994	0.053	0.089	0.097	1.42	2.36	2.60
1995	0.054	0.090	0.098	1.45	2.39	2.62
1996	0.055	0.091	0.100	1.47	2.42	2.65
1997	0.056	0.092	0.101	1.50	2.45	2.68
1998	0.058	0.093	0.102	1.53	2.47	2.71
1999	0.059	0.094	0.103	1.56	2.50	2.74
2000	0.060	0.095	0.104	1.59	2.53	2.77
2001	0.061	0.096	0.105	1.62	2.56	2.79
2002	0.062	0.097	0.106	1.64	2.59	2.82
2003	0.063	0.098	0.107	1.67	2.62	2.85

SOURCES: (1) CERI (based on a forecast using the CERI Oil and Gas Pricing Model). This model derives natural gas prices by using the conventional linkages between domestic natural gas prices and oil prices; and (2) international and domestic oil prices.

NOTE: These prices are net of royalties and taxes.

TABLE A.6

GASOLINE FROM OIL SAND OPTION

Year	Synthetic Gasoline Output ($10^3 m^3$)	Make-up Gasoline Requirement ($10^3 m^3$)	Make-up Gasoline Costs[a] ($1982 x 10^6)
1975	0	2 606	572
1976	0	2 606	535
1977	0	2 606	590
1978	191	2 415	547
1979	636	1 970	558
1980	1 462	1 144	445
1981	1 653	953	358
1982	1 907	699	247
1983	2 098	508	158
1984	2 606	0	0
1985	2 606	0	0
1986	2 606	0	0
1987	2 606	0	0
1988	2 606	0	0
1989	2 606	0	0
1990	2 606	0	0
1991	2 606	0	0
1992	2 606	0	0
1993	2 606	0	0
1994	2 606	0	0
1995	2 606	0	0
1996	2 606	0	0
1997	2 606	0	0
1998	2 606	0	0
1999	2 606	0	0
2000	2 606	0	0
2001	2 606	0	0
2002	2 606	0	0
2003	2 606	0	0

[a]Includes refining charges on make-up gasoline only.

TABLE A.7

AVERAGE INTERNATIONAL OIL PRICE LANDED IN CANADA

Year	1982 $Cdn/m^3	1982 $Cdn/bbl	Annual Escalation Rate
1975	145	23	0
1976	132	21	-9.5
1977	151	24	14.3
1978	151	24	0
1979	201	32	33.3
1980	296	47	47.0
1981	283	45	-4.3
1982	264	42	-6.6
1983	227	36	-14.0
1984	214	34	-5.5
1985	214	34	0
1986	214	34	0
1987	220	35	3
1988	220	35	0
1989	227	36	3
1990	227	36	0
1991	233	37	2.8
1992	239	38	2.7
1993	239	38	0
1994	245	39	2.6
1995	252	40	2.5
1996	252	40	0
1997	258	41	2.5
1998	264	42	2.4
1999	277	44	4.8
2000	283	45	2.3
2001	289	46	2.2
2002	296	47	2.2
2003	302	48	2.1

SOURCE: CERI data and forecast.

TABLE A.8

ALBERTA METHANOL OPTION OPERATING COSTS
($1982 x 10^6)

Year	Non-Fuel Operating Cost	Feedstock Costs	Cosolvent Costs	Make-up Gasoline Costs
1975	0	0	0	141
1976	0	0	0	132
1977	22	7	147	0
1978	22	8	147	0
1979	22	8	147	0
1980	22	9	147	0
1981	22	9	147	0
1982	22	10	147	0
1983	22	12	147	0
1984	22	12	147	0
1985	22	12	147	0
1986	22	12	147	0
1987	22	13	147	0
1988	22	13	147	0
1989	22	13	147	0
1990	22	13	147	0
1991	22	14	147	0
1992	22	14	147	0
1993	22	14	147	0
1994	22	15	147	0
1995	22	15	147	0
1996	22	15	147	0
1997	0	0	0	232
1998	0	0	0	238
1999	0	0	0	244
2000	0	0	0	249
2001	0	0	0	255
2002	0	0	0	261
2003	0	0	0	267

NOTE: Assumes refining costs for make-up gasoline are $47/m^3. The Alberta plant produces at full capacity, but only 73 percent of its output is used as motor fuel. Therefore, the costs have been scaled down accordingly.

TABLE A.9

ONTARIO METHANOL OPTION OPERATING COSTS
($1982 x 10^6)

Year	Non-Fuel Operating Cost	Feedstock Costs	Cosolvent Costs	Make-up Gasoline Costs
1975	0	0	0	215
1976	0	0	0	201
1977	30	23	201	0
1978	30	25	201	0
1979	30	25	201	0
1980	30	25	201	0
1981	30	25	201	0
1982	30	27	201	0
1983	30	30	201	0
1984	30	30	201	0
1985	30	30	201	0
1986	30	30	201	0
1987	30	31	201	0
1988	30	31	201	0
1989	30	31	201	0
1990	30	32	201	0
1991	30	32	201	0
1992	30	33	201	0
1993	30	33	201	0
1994	30	34	201	0
1995	30	34	201	0
1996	30	34	201	0
1997	0	0	0	338
1998	0	0	0	346
1999	0	0	0	354
2000	0	0	0	361
2001	0	0	0	369
2002	0	0	0	377
2003	0	0	0	386

NOTE: Assumes refining costs for make-up gasoline are $\$63/m^3$.

TABLE A.10

QUEBEC METHANOL OPTION OPERATING COSTS
($1982 x 10^6)

Year	Non-Fuel Operating Cost	Feedstock Costs	Cosolvent Costs	Make-up Gasoline Costs
1975	0	0	0	215
1976	0	0	0	202
1977	30	26	201	0
1978	30	28	201	0
1979	30	28	201	0
1980	30	29	201	0
1981	30	29	201	0
1982	30	30	201	0
1983	30	34	201	0
1984	30	34	201	0
1985	30	34	201	0
1986	30	34	201	0
1987	30	34	201	0
1988	30	34	201	0
1989	30	34	201	0
1990	30	36	201	0
1991	30	36	201	0
1992	30	36	201	0
1993	30	36	201	0
1994	30	37	201	0
1995	30	37	201	0
1996	30	38	201	0
1997	0	0	0	339
1998	0	0	0	347
1999	0	0	0	355
2000	0	0	0	362
2001	0	0	0	370
2002	0	0	0	378
2003	0	0	0	386

NOTE: Assumes refining costs for make-up gasoline are $63/m^3$.

TABLE A.11

PROJECT PRICE DEFLATOR

Year	Deflator
1975	0.560
1976	0.607
1977	0.658
1978	0.711
1979	0.782
1980	0.851
1981	0.947
1982	1.000
1983	1.050
1984	1.100
1985	1.160
1986	1.210
1987	1.270
1988	1.330
1989	1.400
1990	1.460
1991	1.530
1992	1.610
1993	1.690
1994	1.770
1995	1.850
1996	1.940
1997	2.010
1998	2.080
1999	2.150
2000	2.230
2001	2.310
2002	2.390
2003	2.470

SOURCES: Based on Statistics Canada GNE deflator and CERI forecasts.

TABLE A.12

OIL SANDS PLANT CONSTRUCTION FINAL DEMAND EXPENDITURES
(millions of 1974 dollars)

Commodities	Nfld	NS	NB	Que	Ont	Man	Sask	Alta	BC	Canada	Imports	Total
Natural Gas	0	0	0	0	0	0	0	2	0	2	0	2
Services Incidental to Mining	0	0	0	0	0	0	0	2	0	2	0	2
Plastic Pipe Fittings and Sheet	0	0	0	0	1	0	0	1	0	2	0	2
Prefabricated Wood Structures	0	0	0	2	3	0	0	20	0	24	0	24
Office Furniture	0	0	0	0	1	0	0	0	0	2	0	2
Steel Pipes and Tubes	0	0	0	2	19	0	0	12	0	33	18	51
Tanks	0	0	0	6	10	0	0	5	0	22	18	40
Beams and Other Structural Steel	0	0	0	0	12	0	0	6	0	19	1	20
Prefabricated Metal Structures	0	0	0	5	19	0	0	6	0	31	16	47
Fuel Burning Equipment	0	0	0	1	7	0	0	4	0	11	5	16
Pumps, Compressors and Blowers	0	0	0	7	14	0	0	2	0	23	9	32
Conveyors, Hoisting Machinery	0	0	0	0	18	0	0	2	0	20	26	46
Industrial Trucks, Tractors, Trailers	0	0	0	0	7	0	0	0	0	7	12	20
Industry Specific Machinery	0	0	0	11	66	0	0	22	0	87	87	174
Power Driven Hand Tools	0	0	0	0	1	0	0	3	0	5	7	12
Office Machines and Equipment	0	0	0	0	0	0	0	0	0	0	1	1
Communications Equipment	0	0	0	0	0	0	0	0	0	1	2	3
Industrial Electric Equipment	0	0	0	4	16	0	0	4	0	24	17	42
Concrete Basic Products	0	0	0	0	1	0	0	7	0	8	1	9
Wool and Thermal Insulation Materials	0	0	0	1	4	0	0	1	0	5	5	10
Naphtha	0	0	0	0	0	0	0	6	0	6	0	6
Industrial Chemical Preparations	0	0	0	0	2	0	0	0	0	2	0	2
Measuring, Control Instruments	0	0	0	2	7	0	0	2	0	10	7	17
Non-Residential Construction	0	0	0	0	0	0	0	2	0	2	0	2
Gas and Oil Facility Construction	0	0	0	10	38	0	0	41	1	90	46	136
Air Transportation	0	0	0	0	1	0	0	4	0	5	0	6
Truck Transportation	0	0	0	1	2	0	0	2	1	5	1	7
Bus Transportation	0	0	0	0	2	2	0	12	0	16	0	16
Pipeline Transportation	0	0	0	0	0	0	0	2	0	2	0	2
Electric Power	0	0	0	0	0	0	0	12	0	12	0	12
Gas Distribution	0	0	0	0	0	0	0	2	0	2	0	2
Wholesaling Margin	0	0	0	7	32	0	0	16	0	55	0	55
Repair Service	0	0	0	4	5	0	0	9	0	19	2	20
Retailing Margin	0	0	0	0	1	0	0	1	0	2	0	2
Other Real Estate and Financial Services	0	0	0	0	1	0	0	38	0	40	0	41
Insurance and Worker Compensation	0	0	0	0	0	0	0	5	0	5	0	5
Other Rent	0	0	0	0	0	0	0	4	0	4	0	4
Services to Business Management	0	0	0	1	2	0	0	2	0	5	0	6

Table A.12 (cont'd)

Commodities	Nfld	NS	NB	Que	Ont	Man	Sask	Alta	BC	Canada	Imports	Total
Accommodation Services	0	0	0	0	0	0	0	1	0	2	0	2
Meals	0	0	0	0	0	0	0	43	0	43	0	43
Transportation Margins	0	0	0	2	9	0	0	5	0	16	0	16
Commodity Indirect Taxes	0	0	0	2	7	0	0	4	0	13	0	13
Other Indirect Taxes	0	0	0	0	0	0	0	5	0	5	0	5
Wages and Salaries	5	8	6	35	44	4	4	375	39	521	17	538
Supplementary Labour Income	1	2	2	9	11	1	1	94	10	130	5	135
Other Operating Surplus	0	0	0	5	12	0	0	73	0	90	6	97
TOTAL	6	10	8	117	364	7	5	859	51	1420	308	1743

SOURCE: Based on cost information obtained from Bechtel Canada, Loram International Ltd., Monenco Limited, and Alsands Energy Ltd., see G. W. Douglas and J. A. MacMillan, Interregional Economic Impacts of the Alberta Alsands Project, Client Research Report No. 82-2 (Calgary: Canadian Energy Research Institute, September 1982), Appendix B.

NOTE: Totals may not add due to rounding.

TABLE A.13

ALBERTA METHANOL PLANT CONSTRUCTION FINAL DEMAND EXPENDITURES
(thousands of 1974 dollars)

Commodities	Que	Ont	Alta	BC	Canada	Imports	Total
Sand and Gravel	0	0	96	0	96	0	96
Prefabricated Buildings and Structures	0	0	592	0	592	0	592
Prefabricated Wood Structures	0	0	567	0	567	0	567
Steel Bars and Rods	0	0	136	0	136	0	136
Line Pipe, Steel, for Oil and Gas	128	129	88	0	344	84	429
Steel Pipes and Tubes	622	628	428	0	1678	410	2088
Tanks	254	514	525	260	1553	168	1721
Structural Steel	0	0	924	0	924	0	924
Prefabricated Metal Structures	0	0	987	0	987	0	987
Steel Sheet	0	0	639	0	639	0	639
Heat Equipment	954	3582	3093	418	8047	5666	13714
Valves	383	387	263	0	1033	253	1286
Meters	0	87	63	0	150	97	247
Pumps, Compressors, Blowers	1463	2318	0	352	4122	1248	5370
Conveyors, Hoisting Machinery	0	115	0	0	115	112	227
Materials Handling Equipment	0	686	0	0	686	0	686
Industry-Specific Machinery	582	0	150	149	881	725	1606
Power Driven Hand Tools	0	0	257	0	257	0	257
Wire and Cable, Insulated	203	307	418	0	927	100	1027
Conduit, Switches, Wiring Devices	178	270	367	0	815	88	903
Cement	0	0	258	0	258	0	258
Concrete Basic Products	0	0	334	0	334	0	334
Insulation Materials	0	344	0	0	344	0	344
Asb. and Asb.-Cement Products	341	0	0	0	341	0	341
Motor Gasoline	0	0	1206	0	1206	0	1206
Asphalt, Coal Products	0	0	74	0	74	0	74
Paints and Related Products	0	0	155	0	155	0	155
Measuring, Control Instrument	0	347	253	0	599	387	987
Safety Equipment	0	0	46	0	46	0	46
Railway Transportation	222	307	0	24	554	552	1105
Truck Transportation	0	0	133	0	133	0	133
Repair Service	0	0	1768	0	1768	0	1768
Machinery, Equipment Rental	0	0	2407	0	2407	0	2407
Commodity Indirect Taxes	82	146	181	17	426	158	584
Wages and Salaries	0	0	20306	0	20306	0	20306
Supplementary Labour Income	0	0	5187	0	5187	0	5187
Other Operating Surplus	0	0	8687	0	8687	0	8687
TOTAL	5402	10165	50474	1219	67260	10916	78176

SOURCES: Industry sources and CERI.

NOTE: Totals may not add due to rounding.

TABLE A.14

ONTARIO METHANOL PLANT CONSTRUCTION FINAL DEMAND EXPENDITURES
(thousands of 1974 dollars)

Commodities	Que	Ont	Canada	Imports	Total
Sand and Gravel	0	95	95	0	95
Prefabricated Buildings and Structures	0	592	592	0	592
Prefabricated Wood Structures	0	567	567	0	567
Steel Bars and Rods	0	135	135	0	135
Line Pipe, Steel, for Oil and Gas	130	219	350	84	434
Steel Pipes and Tubes	636	1069	1704	410	2114
Tanks	260	1312	1571	168	1739
Structural Steel	0	924	924	0	924
Prefabricated Metal Structures	0	987	987	0	987
Steel Sheet	0	639	639	0	639
Heat Equipment	974	7171	8145	5666	13812
Valves	391	658	1049	253	1302
Motors	0	152	152	97	249
Pumps, Compressors, Blowers	1483	2721	4204	1248	5452
Conveyors, Hoisting Machinery	0	117	117	112	230
Materials Handling Equipment	0	699	699	0	699
Industry-Specific Machinery	594	300	895	725	1620
Power Driven Hand Tools	0	257	257	0	257
Wire and Cable, Insulated	287	731	938	100	1038
Conduit, Switches, Wiring Devices	182	643	825	88	913
Cement	0	258	258	0	258
Concrete Basic Products	0	334	334	0	334
Insulation Materials	0	351	351	0	351
Asb. and Asb.-Cement Products	348	0	348	0	348
Motor Gasoline	0	1206	1206	0	1206
Asphalt, Coal Products	0	74	74	0	74
Paints and Related Products	0	155	155	0	155
Measuring, Control Instrument	0	606	606	388	994
Safety Equipment	0	45	45	0	45
Railway Transportation	111	0	111	552	663
Truck Transportation	0	247	247	0	247
Repair Service	0	1768	1768	0	1768
Machinery, Equipment Rental	0	2407	2407	0	2407
Commodity Indirect Taxes	82	344	426	158	584
Wages and Salaries	0	20306	20306	0	20306
Supplementary Labour Income	0	5187	5187	0	5187
Other Operating Surplus	0	8887	8887	0	8887
TOTAL	5397	61864	67250	10916	78166

SOURCES: Industry sources and CERI.

NOTE: Totals may not add due to rounding.

TABLE A.16

QUEBEC METHANOL PLANT CONSTRUCTION FINAL DEMAND EXPENDITURES
(thousands of 1974 dollars)

Commodities	Que	Ont	Canada	Imports	Total
Sand and Gravel	94	0	94	0	94
Prefabricated Buildings and Structures	591	0	591	0	591
Prefabricated Wood Structures	569	0	569	0	569
Steel Bars and Rods	150	0	150	0	150
Line Pipe, Steel, for Oil and Gas	138	228	366	88	455
Steel Pipes and Tubes	641	1058	1699	410	2110
Tanks	656	908	1564	168	1731
Structural Steel	924	0	924	0	924
Prefabricated Metal Structures	942	0	941	0	942
Steel Sheet	639	0	639	0	639
Heat Equipment	2742	5359	8101	5666	13767
Valves	527	521	1048	253	1300
Motors	15	135	150	97	247
Pumps, Compressors, Blowers	1854	2342	4195	1248	5443
Conveyors, Hoisting Machinery	0	116	116	112	228
Materials Handling Equipment	350	346	696	0	696
Industry-Specific Machinery	760	148	908	725	1623
Power Driven Hand Tools	258	0	258	0	258
Wire and Cable, Insulated	424	525	949	102	1061
Conduit, Switches, Wiring Devices	369	457	826	88	914
Cement	258	0	258	0	253
Concrete Basic Products	329	0	329	0	328
Insulation Materials	351	0	351	0	351
Ash. and Ash.-Cement Products	351	0	351	0	351
Motor Gasoline	677	529	1206	0	1206
Asphalt, Coal Products	70	0	70	0	70
Paints and Related Products	156	0	156	0	156
Measuring, Control Instrument	43	464	506	327	833
Safety Equipment	45	0	45	0	45
Railway Transportation	0	133	133	552	685
Truck Transportation	0	133	303	0	303
Taxicab Transportation	170	0	170	0	170
Repair Service	1768	0	1768	0	1768
Machinery, Equipment Rental	2407	0	2407	0	2407
Commodity Indirect Taxes	400	100	500	83	584
Wages and Salaries	20306	0	20306	0	20306
Supplementary Labour Income	5187	0	5187	0	5187
Other Operating Surplus	8687	0	8687	0	8687
TOTAL	53724	13500	67225	10786	78011

SOURCES: Industry sources and CERI.

NOTE: Totals may not add due to rounding.

APPENDIX B
BACKGROUND INFORMATION

Appendix B

BACKGROUND INFORMATION

B.1 The Concept of Supply Price

The vehicle that has been used to obtain the supply prices is a model first used by Bradley.[1] Though relatively simple, Bradley's model was designed to serve the demands of theoretical rigor as well as empirical feasibility. Unlike others,[2] Bradley proposed to tackle the problem of capital cost analysis by calculating the amounts that ought to be charged for future output so that all original development and other costs are recouped.

The simple model is derived as follows: First, an estimate is obtained of the amount (Z) which must be realized on each cubic metre produced in order to repay original investment expenditure (I) and the cost of capital. Hence:

$$\sum_{n=1}^{N} \frac{I_n}{(1+r)^n} = \sum_{n=1}^{N} \frac{Z \times Q_n}{(1+r)^n}$$

where

Q is the output in bbls and $[1/(1+r)]^n$ is the discounting factor applied to a time period n using a discount rate r .

Since Z is a constant (per m^3) amount, it can be taken outside of the summation sign and therefore:

$$Z = \frac{\sum_{n=1}^{N} \frac{I_n}{(1+r)^n}}{\sum_{n=1}^{N} \frac{Q_n}{(1+r)^n}}$$

Defined in this fashion Z stands for a constant average amount per cubic metre that the producer would need to receive such that the

present value of this amount times output level over the project life should just equal the present value of the total investment (development) expenditure. Hence Z accounts for the operator's opportunity cost of capital and therefore for normal profit.[3] While the numerator of Z stands simply for the present worth of the investment expenditure, the denominator has been described by Adelman as the "present barrel equivalent factor."

The overall costs, however, which are to be recovered via production must also include the operating costs OC. Analogously:

$$\sum_{n=1}^{N} \frac{OC_n}{(1+r)^n} = \sum_{n=1}^{N} \frac{Y \times Q_n}{(1+r)^n}$$

therefore,

$$Y = \frac{\sum_{n=1}^{N} \frac{OC_n}{(1+r)^n}}{\sum_{n=1}^{N} \frac{Q_n}{(1+r)^n}}$$

Y, derived in a similar way to Z, is the constant average amount per barrel such that the present value of this amount, when multiplied by output over the project's life, is just equal to the present value of the total operating expenditures. When Y is computed in this way, the opportunity cost of all operating outlays will also be accounted for.

Adding now the two types of "required returns" will yield a Marshallian supply price Sp, standing for the real cost of the resource development, assuming no payments for the resources extracted. Thus:

$$Sp = Z + Y$$

$$Sp = \frac{\sum_{n=1}^{N} \frac{I_n}{(1+r)^n}}{\sum_{n=1}^{N} \frac{Q_n}{(1+r)^n}} + \frac{\sum_{n=1}^{N} \frac{OC_n}{(1+r)^n}}{\sum_{n=1}^{N} \frac{Q_n}{(1+r)^n}}$$

or

$$Sp = \frac{\sum_{n=1}^{N} \frac{I_n + OC_n}{(1+r)^n}}{\sum_{n=1}^{N} \frac{Q_n}{(1+r)^n}}$$

Hence, the Sp is a constant (per barrel) average amount which, if multiplied by output and discounted, will equal the present value of all capital and operating expenditures. It must hold, then, that:

$$\sum_{n=1}^{N} \frac{Sp \times Q_n}{(1+r)^n} = \sum_{n=1}^{N} \frac{I_n}{(1+r)^n} + \sum_{n=1}^{N} \frac{OC_n}{(1+r)^n}$$

The proper interpretation of the above supply price formula is very important. It should be noted that it was developed with conventional crude oil production in mind, where the future output levels (Q_n) constitute a rather uncertain variable depending on the size and productivity of the reservoir. If used for an oil sands operation, with virtual certainty as of the resource deposit, the supply price would imply that a greater confidence can be placed in the results obtained. On the other hand, the risk of working with new technology and large initial investment may be just as great.

The discount rate r should be viewed in the usual manner, whereby it stands for the rate of return on investment necessary to attract capital. Because of the inclusion of both development and operating expenses (both discounted to present values), we can conclude that the obtained Sp is a price which includes normal profit.

It ought to be recognized, however, that the selection of the discount rate will substantially influence the magnitude of the supply price and hence the profitability of each project. Many proposals

have been put forward suggesting various ways of estimating the "proper" level of the rate of discount.[4] Since no general agreement exists as to what the rate of discount should be, we shall follow here the usual practice of using a range of various real rates.[5]

This procedure has been used to generate supply price estimates for the hypothetical oil sands plant and also for methanol produced from natural gas.

B.2 Problems with Pioneer Plants

Various pioneering plants such as Syncrude have been plagued with cost overruns and performance shortfalls particularly in the past decade and a half. This occurred mainly due to lack of accurate cost information available to decision makers and incorrect capital expenditure assessments. Projects which appear to be economic at the initial stage may actually prove to be uneconomic in the final analysis.

Several factors which may give rise to changes in plant costs while construction is underway can generally be identified. These include:

- changes in project scope or design;
- inflation;
- regulatory changes;
- bad luck; and
- management practices.

Each is discussed below.

Scope Changes. Discretionary changes, such as a change in the proposed plant design capacity or in the product slate, can greatly affect plant costs. Capacity might be decreased in order to reduce capital costs or increased to take advantage of economies of scale, but changes of this sort would normally be accounted for before going beyond the design stage of the project. Changes in the market for the plant's output resulting in capacity adjustments or a change in the product slate are less predictable.

Inflation. Inflation assumed a key role in spurring cost escalations over the 1970s and early 1980s. It is a phenomenon recognized by cost engineers and is anticipated. Although most prices (and costs) rise over time, it is worth noting that construction labour costs are responsive to market conditions. That is, in times of tight labour supply, costs can be expected to be abnormally high. Likewise, due to the highly competitive nature of the construction industry, costs would be expected to fall or to be escalating at or below the rate of general inflation during slack periods.

Regulatory Changes. Changes in environmental regulations, health or safety standards and other regulations also have an impact on plant costs. Discussions with regulatory officials to ensure that no unanticipated changes in the regulatory environment are likely to occur after project inception would hopefully preclude any unexpected project costs or delays. The legislative or regulatory process is rarely expeditious and, in order to avoid undue delay, projects can be undertaken pending government or regulatory approval. If the legislative outcome is other then expected, costs can be much higher than projected.

Bad Luck. Strikes, inclement weather, late delivery of materials and equipment and unforeseen labour shortages are a few of the many circumstances which can potentially affect costs adversely. These factors are beyond the control of project owners/managers and cannot be accounted for with high accuracy in cost estimates.

Management Practices. Inexperienced and/or ineffective management may be responsible for poor project scheduling which can result in inefficient use of both human and physical resources. Every project has an optimum time frame within which it should be developed. Any deviation results in increased costs.

Inadequate cost controls can result in unnecessary cost overruns. Also, weak supervision of contractors leads to higher capital and operating costs than anticipated.

The 1981 Rand Corporation study on Understanding Cost Growth, from which most of the information in this section is derived, makes a distinction between those factors which can change cost estimates and those which effect the accuracy of the cost estimate.[6]

It was found that scope changes, unanticipated inflation, unanticipated regulatory changes and bad luck were not the principal causes of cost underestimation for pioneer plants. Rather, most of the errors were explained by the following three factors:

- introduction of unproven or pioneering technology;
- the degree of project definition; and
- complexity of the plant.

A discussion of each follows:

Introduction of Unproven Technology. Examples of situations where unforeseen problems might arise include when a new chemical conversion process is being implemented, when significant scale-ups of previously constructed units are undertaken or when new equipment or feedstocks are introduced. The oil sands plant falls into this category of unproven technology. Problems encountered in these situations could result in design modifications. These differ from what has been termed "scope" changes because they result from attempts to resolve previously unidentified problems. Scope changes are largely discretionary rather than necessary in order for the plant to operate.

Degree of Project Definition. Detailed and comprehensive information for a first-of-a-kind plant is often not supplied to the cost estimator. Due to the lack of experience with the plant or process, errors and omissions in project information are inevitable and cost estimates are necessarily less accurate. The oil sands plant is a case in point.

Another problem which occurs is one which has been referred to as the "Anytown Syndrome." When no experience is available, project designers draw up plans for a typical plant at a typical location. Evidence suggests that a hypothetical plant built in "Anytown" always costs less than one built in a real place. This could have especially significant consequences for construction sites such as in the Canadian North (e.g., Fort McMurray).

Plant Complexity. The higher the degree of complexity, the more vulnerable the pioneer project is to problems and hence to cost estimation errors. An oil sands plant employs a much more complex

technological process relative to a methanol plant. Thus the oil sands project is more prone to cost overruns and performance shortfalls.

The key sources of misestimation of costs for pioneer plants have been presented. Other factors which affect the success or failure to develop accurate cost estimates include experience of key personnel, extent of turnover in key staff and the experience of a firm with the particular process being employed. In the case of the oil sands plant, the production process is employed with little experience behind it whereas by the mid-1970s, considerable experience with methanol plants had been gained. Finally, the extent to which a project embodies incentives for accurate estimation and cost control can play a large role in determining whether a project is completed within the budget.

8.3 Joint Product Crediting

When a barrel of synthetic crude oil is run through an Alberta refinery, on average about 40 percent of the yield is gasoline. Many other products are also produced varying from fuel oil to lubricants to petrochemical feedstocks. However, the majority of these products are produced in small quantities. Diesel fuel and fuel oil are the two most important products besides gasoline. They compose about 50 percent of the total refinery yield. Gasoline, diesel and fuel oils will typically account for about 90 percent of the yield.

It is therefore necessary to distinguish between the costs of obtaining gasoline on the one hand and associated products on the other when synthetic crude oil is refined. There are several ways of doing this. One is to provide a credit for the joint products of diesel fuel and fuel oil by accounting for their share of the revenue barrel.

Although the gasoline yield accounts for 40 percent of total refinery yield by volume, more than 40 percent of the total revenue produced by selling one cubic metre of refined products is generated by gasoline.

The value of gasoline to refiners is about 10 percent higher than an average of the value of the other products. If the value of gasoline to the refiner is $0.30/litre and the average value of the other products is $0.26/litre, at the typical yields gasoline provides about 45 percent of the revenue received from selling one cubic metre of refined product.[7]

$0.30/litre for gasoline x 400 litres = $120.00
$0.26/litre for joint products x 600 litres = $156.00
Total Revenue = $276.00
Gasoline Contribution = 120.00 ÷ 276.00 = 43%

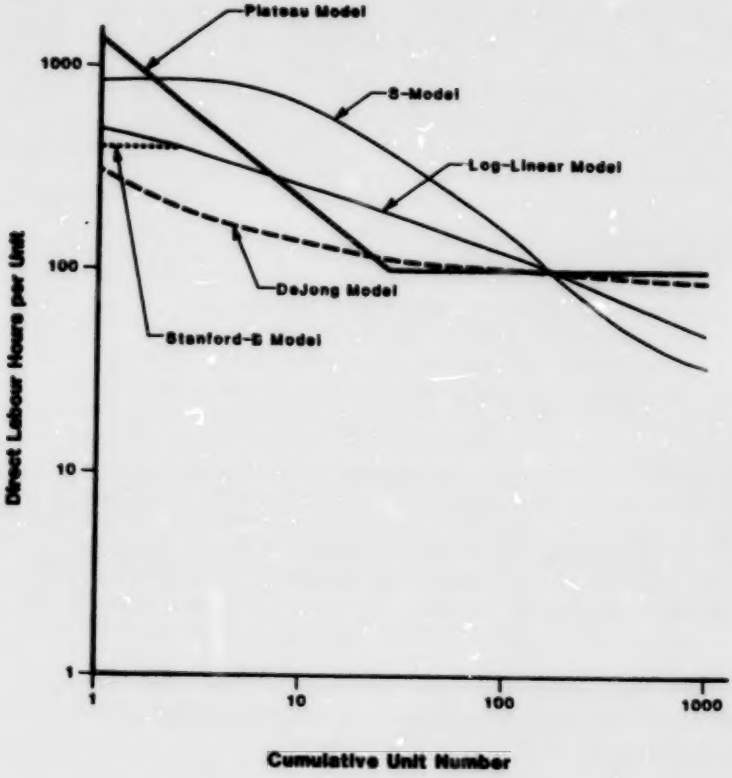
To provide a joint product credit, approximately 45 percent of the supply price of synthetic crude oil has been included in the synthetic gasoline option supply price estimates. Where oil has been imported (or conventional domestic oil used) to produce make-up gasoline the same procedure is followed providing credit to the imported oil cost.

B.4 Learning Curve Effects: Background

The existence of a "learning curve" phenomenon was first recognized in the 1930s when T. P. Wright observed a negative relationship between an increasing quantity of units produced and the amount of labour input required in the process of manufacturing.[8] Lower unit labour costs were associated with increasing accumulated production. Wright further observed that the specification of the relationship resembled a constant mathematical function even though the actual specification parameters varied with the particular manufacturing process being studied.

During World War II observed learning curve information was used to aid in the estimation of costs and time required to field airplanes and ships for the war. Since that time considerable effort has been expended to improve understanding of the learning curve phenomenon, although most of the effort has been concentrated on manufacturing rather than on the effects of learning associated with construction.

This research has identified several different types of relationships, the most common being the log-linear, plateau, Stanford-B, DeJong and S-models. These are graphically depicted in Figure B.1.[9] These different functions have been developed as a result of rising actual production data from various industrial processes. For example, the Boeing Company found that the Stanford-B model most closely described its experience in manufacturing the Boeing 707 aircraft.[10]



SOURCE: L.E.Yelle, DECISION SCIENCES (see footnote 9).

FIGURE B.1: VARIOUS LEARNING CURVE MODELS

B.4.1 Learning Curve Effects in Manufacturing

Recent investigations into industrial applications of learning curve research have involved identifying the shape of the learning curve, parameter estimation, setting of time standards and incentives, cost control and purchasing-bidding functions.

Knowledge of the actual shape of the curve relevant for a given production process is of the utmost importance if the function is to be useful for predicting future performance. None of the above-mentioned functions has a constant slope and none has a shape similar to any of the others. There exists considerable disagreement in the literature as to the specification of learning curves. A study by Billon in 1966 concluded that the slope of the curve varies among companies producing similar products, among dissimilar products produced by a single firm, and among variants of a basic product type manufactured by the same firm.[11] Some general rules have, however, been identified. Apparently, different levels of learning are encompassed by learning curve phenomena. On one level is labour learning, on another, machine learning. Researchers have observed that operations which are labour intensive, or are paced by labour, exhibit steeper-sloped learning curves in comparison with machine-paced operations. Labour learning may be further disaggregated into operator and organizational learning. New operators of machinery learn while operating and normally become more efficient in performing the requisite tasks. While production is continuing, however, plant foremen and managerial personnel learn to better organize production by changing various characteristics of operation.

Yelle has noted that the magnitude of the cost decrease associated with the learning curve will depend upon product complexity and the amount of pre-production planning done.[12]

Discontinuities may occur in the learning curve. These are likely to occur when changes are introduced, such as model changes or product design changes. However, this may also occur when production of a product is intermittent. Abstracting from discontinuities, most researchers have observed that eventually a plateau on the learning curve is reached where learning and subsequent cost reductions cease to occur. In one study by Baloff a learning plateau was observed in twenty out of twenty-eight cases.[13] A general conclusion given was that plateauing is more likely to occur if the industry is machine-intensive rather than labour-intensive.

Footnotes

[1]P. G. Bradley, The Economics of Crude Petroleum Production (Amsterdam: North-Holland Publishing Co., 1967), pp. 13-30. See also M. A. Adelman, The World Petroleum Market (Baltimore: The John Hopkins University Press, 1972), pp. 48-53.

[2]See for instance, H. Hotelling, "A General Mathematical Theory of Depreciation," Journal of the American Statistical Association, No. 9 (1925), pp. 340-353.

[3]In a strict economic sense, normal profit is defined as the amount earned by the producer necessary to prevent him from leaving his present activity. It reflects the producer's opportunity cost which is in turn estimated by the return he could secure in the best alternative open to him.

[4]See for instance, Canada, Treasury Board, Benefit-Cost Analysis Guide (Ottawa: Information Canada, 1976), pp. 22-26.

[5]The real rate of discount range usually suggested for analysis like the present one varies between 5 and 15 percent. See Ibid., p. 26.

[6]The Rand Corporation, Understanding Cost Growth and Performance Shortfalls in Pioneer Process Plants, Report R-2569-AOE (Santa Monica, California: The Rand Corporation, 1981).

[7]These prices are an average of Alberta retail prices for the last quarter of 1983.

[8]T. P. Wright, "Factors Affecting the Cost of Airplanes," Journal of Aeronautical Sciences, Vol. 3, No. 4 (1936), pp. 122-128.

[9]L. E. Yelle, "The Learning Curve: Historical Review and Comprehensive Survey," Decision Sciences, Vol. 10 (1979), p. 304.

[10]Ibid., p. 304.

[11]Ibid., p. 305.

[12]Ibid., p. 314.

[13]Baloff, "Startups in Machine-Intensive Production Systems," Journal of Industrial Engineering, Vol. 17, No. 1 (1966), pp. 25-32.

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